U.S. Agency for International Development

Regional Center for Southern Africa

In collaboration with:

Electricity Control Board of Namibia

Power Market Restructuring Issues:

Integrated Monopoly → Single Buyer → Wholesale Market

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Executive Summary

The Electricity Control Board of Namibia (ECB) and the United States Agency for International Development's Regional Center for Southern Africa agreed to collaborate on two important regulatory issues facing Namibia. First, what steps need to be taken by the ECB to assure a successful implementation of a Single-Buyer market model, a process already underway at NamPower? Second, what steps would be needed to facilitate a successful transition to a Wholesale Market model?

These issues have regional implications to the electricity sector and while the Report deals specifically with the situation in Namibia, there is utility for several Southern African countries facing similar concerns.

For the purposes of this report, the term "Single-Buyer" is used to indicate a market structure in which a single entity acquires a portfolio of energy supply and energy demand-side resources to meet the demands of all retail consumers. This is presently being implemented by NamPower, regardless of the distribution utility providing their service.

The term "Wholesale Market Model" is used to indicate a market structure in which several regional electricity distributors acquire portfolios of energy supply and energy demand resources from competing generators, energy service companies, and end-use customers to meet their respective needs. This could include purchases from NamPower and purchases from other wholesale market sellers from South Africa and other countries within the Southern Africa Power Pool (SAPP).

The most imminent task facing the ECB in implementing a successful Single-Buyer structure is to adopt an integrated resource planning (IRP) rule, to oversee the development of resource plans that consider energy supply, energy efficiency, and demand response resources on an equal basis. The importance of an IRP requirement cannot be exaggerated. It is the keystone to a successful, economic and reliable power supply. The IRP approach being used in South Africa, under the direction of the National Electricity Regulator (NER) is used as the model for consideration in Namibia. Chapter 2 sets forth the discussion of the IRP process, and Chapter 3 sets forth a Model Rule for consideration in Namibia.

The balance of the Report examines the numerous elements that would need to be addressed in order for Namibia's regional electricity distributors to be successful at managing their own energy portfolios. These include ensuring that a competitive wholesale market is available to them, something that is far from certain at the present time. It also includes establishing market rules and market monitoring programs, to assure that large buyers and sellers in the market do not develop and exercise market power. This will require international cooperation among the member nations of SAPP, as the vast majority of the potential competitive sources of energy supply to Namibia are outside its national boundaries.

The report is fairly skeptical about the prognosis for evolution of a competitive wholesale market for Namibia's regional electricity distributors. Experience with emerging electricity markets in other nations strongly suggests that there are important structural barriers to the creation of a competitive wholesale market for Namibia. Most important among these are the small size of the loads of the individual Namibian utilities, and the large size of existing sellers in the wholesale market.

The Report identifies a number of thresholds that would need to be achieved for a successful market to evolve. First, for the Namibian regional electricity distributors, their loads would need to grow to the point where it was economical to support the specialized expertise and analytical tools needed for energy portfolio management. While there are exceptions, our experience is that utilities with demands below about 250 MW typically are not able to support the required expertise. The entire load of Namibia, managed by NamPower as a Single Buyer, is not much larger than this threshold. Dividing the portfolio management responsibility could result in none of the responsible entities having the size or skills to be successful as a portfolio manager.

Second, there would need to be a significant increase in the number of sellers in the Southern Africa wholesale electricity market, to assure that none are dominant enough to exercise market power. We define that threshold to be a level where no individual seller controls a larger share of generation than the typical reserve margins that are maintained on the regional power grid. The basis for this proposed threshold is that, under normal circumstances, no seller would be able to exercise market power. There would be sufficient generation controlled by other sellers (or sufficient enrolled demand response controlled by end-use customers and their service providers) at any time to provide a market-based check and balance on the power of individual sellers. Currently Eskom controls over 80% of the capacity in Southern Africa, some 40,000 megawatts. Turning this amount of capacity into a viable wholesale market implies a minimum of seven to ten large sellers, and would effectively require that Eskom be broken into as many separate entities.

The Report identifies the expertise that would need to be developed within the ECB, within the Ministry, and within the regional electricity distributors in order to make a transition to a wholesale market model. The needs are substantial, will be expensive to implement, and as discussed above, are not likely to be cost-effective unless the total load to be served increases significantly.

The Report also discusses the elements that need to be addressed in purchased power agreements (PPAs). These are equally applicable in a Single-Buyer and Wholesale Market context. The recommendations focus on the need to maintain a diverse portfolio, to ensure the financial viability and political stability of sellers of long-term resources, and to ensure public disclosure of key terms so that all buyers and sellers can participate in an open and transparent marketplace. They also address the crucial issue of provision of reserves for generating capacity to ensure that resources are added to the system (either on the supply-side or on the demand-side) to improve system reliability.

Market rules for wholesale markets are essential to assure the vigor and transparency of the market. The stock exchange model, where every transaction between buyers and sellers is reported in real-time is one key to developing such a market. Another element we recommend is to require that all "major" participants in the market (buyers and sellers) be required to maintain "bid" and "ask" prices for a limited number of standardized market products at all times. These will create a foundation of information upon which parties seeking to negotiate contracts for standard or non-standard products can refer to.

We discuss how the role of the regulator will change if the Namibian utility sector changes to a wholesale market model. The regulator will still have responsibility for all distribution services, but the importance of having well-defined processes in place for evaluating energy resource portfolios will increase significantly.

The Report examines the feasibility of a separate Namibian power pool. The probability of success is low, because of the small number of different resources in Namibia, and the small size of the Namibian market relative to the economical electrical generating unit size in the current wholesale market environment. If small distributed generating resources become more viable in the future, this conclusion would need to be reexamined.

The principal findings of the Report are that:

- A well-defined IRP process is needed in the Single-Buyer framework, and remains important if a transition to a wholesale market model is implemented.

- Namibia is unlikely to achieve benefits from a transition to a wholesale market model, simply due to the small size of its domestic loads, compounded by the small number of viable sellers in the current market. Technological evolution and/or significant load growth could change this dynamic.

- Key reforms in the market structure need to be addressed at the regional level, through the Southern Africa Power Pool, as Namibia is simply too small a portion of the regional load to establish meaningful policies on market design independently.

1. Implementing an Integrated Resource Planning (IRP) Process

The single most essential action for the Electricity Control Board to take in facilitating an orderly, efficient, and economical transition to a Single Buyer form of resource management is to adopt and implement an Integrated Resource Planning (IRP) process.

A Single Buyer structure is characterized by having a single entity, in this case, NamPower, serving as the portfolio manager for the electric supply to all retail customers, acquiring all resources needed to serve load in a competitive wholesale marketplace. In Namibia, it is anticipated that this will be modified slightly, allowing the largest customers to acquire their own power supply resources directly.

In order for the portfolio manager to objectively compare supply-side and demand-side options to meet load requirements, experience has shown that a disciplined IRP is essential. This is driven by two facts. First, customers will typically not themselves invest in demand-side resources with long payback periods, simply because of their high implicit discount rates and low levels of knowledge about energy costs. Second, utilities will typically not invest in demand-side resources if their net operating income levels are driven by sales volumes.

Both of these conditions are present in Namibia today. The typical level of energy efficiency in Namibia is quite low. Market penetration of efficient lighting, air conditioning, motors, appliances, and construction practices is very low. The prices charged by Namibia distribution utilities embed much of the system fixed costs in the variable energy price, which is a very positive element of rate design to encourage efficiency. It does create a situation where increased sales mean increased net income, causing utilities to resist efficiency gains by their customers.

In order to overcome these market barriers to efficiency, regulatory commissions have implemented IRP processes to identify the lowest-cost resources that meet reliability and environmental guidelines, and have adopted ratemaking practices designed to ensure that the utility's least-cost resource plan is also its most profitable resource plan. This report addresses only the first part of this: designing and implementing IRP processes to identify and acquire the best mix of resources to meet a utility's need.

Maximizing the benefits of regional cooperation includes: increasing the pool of available expertise, and minimizing the cost of developing an IRP. The Namibia IRP rule, insofar is as practical, should be consistent with the IRP requirements used in Southern Africa. For this reason, the Model IRP rule in this Report is modeled after the requirement imposed in South Africa.

A Model IRP rule for Namibia is contained in Appendix A. Examples of Integrated Resource Planning Rules are contained in Appendix B to this report. The South Africa National Electricity Regulator "Framework for Integrated Resource Planning In The Electricity Supply Industry" is contained in Appendix C, and the South Africa National Integrated Resource Plan is contained in Appendix D. Appendix E presents the

Regulatory Assistance Project's handbook on Portfolio Management, and Appendix F is information on Efficiency Vermont, an innovative energy efficiency utility.

This document sets forth a roadmap and timeline to implement this essential element of regulation in order to assure successful implementation of the Single Buyer model in Namibia. The roadmap includes:

- Implementing an Integrated Resource Planning Rule
- Setting Forth a Public Process to Adopt and Implement the Rule
- Institutional Framework for Implementing the Integrated Resource Plan(s)
- Timeline for Rulemaking, Plan Preparation, Plan Evaluation, and Implementation

1.1. Implementing an Integrated Resource Planning Rule

The Namibia Electricity Control Board should implement an Integrated Resource Planning Rule as soon as practical, and long before any consideration of a major resource acquisition advances within NamPower and/or other distribution utilities in Namibia. The draft rule should be proposed by the end of 2003, and implemented by mid-year 2004, with initial filings of IRPs before the end of 2004. Necessary institutional changes needed to support demand-side resource acquisition should be implemented before the end of 2004.

Issues to be addressed in the IRP rule include: identifying the entity with lead responsibility for the Plan, load forecasting, supply-side resources, demand-side resources, distributed energy resources, risk management, environmental costing, and the treatment of non-retail industrial customers.

1.1.1. Framework for Preparation of the Plan

South Africa has determined that a single national Integrated Resource Plan is desirable. In the United States, there have been regional energy plans, statewide energy plans, and utility-specific energy plans. Determining the entity responsible for actually developing the integrated resource plan or plans is possibly the most important and politically sensitive decision the ECB will need to make in adopting an IRP process.

The possible entities include the ECB itself, the Ministry of Mines and Energy (MME), NamPower, and the Local Distribution Utilities. In a Single Buyer construct, where NamPower is responsible for securing all resources, it will clearly have the most central major role in development of the Plan(s).

Because of the size of the Namibian energy system and economy, this Report is using an assumption that a single IRP will be developed for the country, with geographic specific elements as to areas of constrained transmission and distribution capacity. For that reason, the ECB, the MME, and/or NamPower are the logical candidates. Without attempting to pre-judge the outcome of this issue through the rulemaking process, for convenience this Report assumes that the NamPower will be the lead agency on a national IRP. The text of the report needs to be read with sufficient flexibility to recognize that another framework may be selected by the ECB.

A second framework issue is the frequency with which IRPs should be developed and submitted to the evaluation process. A cycle of 2 – 3 years is most common in the industry, but the rulemaking process may determine a different cycle is appropriate for Namibia.

1.1.2. Economic Framework for Integrated Resource Planning

The IRP should compare various resource scenarios on a present value basis, using a social discount rate such as a government bond rate that reflects Namibian time preferences for low-risk investments. This will typically be significantly lower than the discount rate for independent power producers or the private industrial sector. The reason for this is that the costs obligated by the Single Buyer will ultimately be borne by the population at large, and it is the discount rate of the buyers of the electricity that is most important.

The analysis should be performed over the life-cycle of the longest-lived resources considered for the portfolio, such as hydro and efficiency, not solely looking at the much shorter life-cycles of fossil-fired power plants. This is necessary to ensure that all resources are compared equitably.

Consideration should be given to applying a zero discount rate to environmental costs. Otherwise, the analysis will always favor any option that indefinitely delays remediation of environmental impacts – by delaying the expense of dealing with environmental impacts, the effective cost is always diminished if a positive discount rate is applied, conceptually making it desirable to never address environmental costs.

1.1.3. Load Forecast

Load forecasting is necessarily imprecise, and the longer the term of the forecast, the greater the imprecision. Nonetheless, where long lead-time resources, such as hydropower construction, development of the Kudu gas field, or long-distance transmission interconnections are considered, a long-term forecast is essential.

Initially, a short-term load forecast of 5-years duration, estimated by customer class and by major end-use should be prepared. Additionally, a more general 20-year forecast should be required, estimated by customer class. The short-term forecast should be the basis of design of pricing programs, energy efficiency programs and short-term resource acquisition. The long-term forecast should guide planning for major long-term resource acquisitions and interconnections.

Because the IRP will compare demand-side and supply-side resources to meet local load requirements, and the demand-side resources can obviate the need for distribution facility augmentation, it is important that at least the short-term forecast be localized to the distribution system level. Since local distribution upgrades require no more than a few years of lead-time, most efficiency alternatives to such upgrades will be available in the five year short range forecast and the 5-year IRP Action Plan. Major supply-side

In a Single Buyer context, evaluation of supply side resources needs to be directly comparable to alternative resources, and the Single Buyer needs to face a regulatory scheme that ensures that the lowest cost alternative is pursued. By addressing all resources on a common framework within the IRP, the Single Buyer can make informed choices between alternative resources.

For Namibia, cross-border trading of electricity is a very important supply-side option. Namibia currently relies heavily on South Africa for its electricity supply, and as the Southern Africa Power Pool (SAPP) expands operations, the opportunities for trading with other Southern African nations will increase. Because of the diversity of resources in Southern Africa – including coal, natural gas, hydroelectricity, and nuclear energy – there are important options that should be considered. An IRP is the best tool for comparing these options with domestic alternatives such as energy efficiency, development of the Kudu facility, and locally-developed renewable energy resources.

1.1.5. Demand side resources

Demand-side resources are extremely promising for Namibia. These include measures applicable to new and existing residential, commercial, and industrial facilities, as well as measures applicable to the agricultural and mining sectors. In addition, efficiency measures applicable to the utility sector hold considerable promise for Namibia.

Demand-side resources have many advantages over supply-side resources. First, they can be acquired in small increments with very short lead-times, matching more precisely the need for new resources. Second, they avoid not only production costs, but also transmission costs, distribution costs, losses, and reserve requirements. Third, they have a daily and seasonal load shape which is equal to the system load, meaning there is typically a larger capacity value than energy value to demand-side resources. Demand-side resources avoid the environmental impacts of generating resources. Demand-side resource acquisition can be geographically focused to address transmission and distribution system constraints. Perhaps most important to Namibia, demand-side resources include a very significant local labor component (on the order of 50% of total cost), something that no supply-side resource can match. For all of these reasons, it is crucial that the demand-side resource evaluation be thorough, and that programs be developed to acquire all cost-effective demand-side resources.

The evaluation of demand-side resources must include all of the costs of developing these decentralized resources. These include transaction costs of setting up programs that deal with thousands of individual customers, creating public awareness of energy efficiency opportunities, and the cost of training and mobilizing contractors to provide these services. Similarly, the evaluation should consider all of the benefits, including non-energy benefits such as improved lighting quality from lighting retrofits, improved reliability of industrial and mining facilities from installation of new motors, and other benefits not directly measurable as energy savings.

Evaluating the availability of demand-side resources is only one element of an IRP; developing the means to acquire these resources is also essential, and is discussed below under Implementing the Plan.

1.1.6. Distributed Energy

Distributed energy resources include both demand-side and supply-side resources. The term, as used here, is limited to small-scale resources that are located in such a manner as to avoid the need for conventional generation, transmission, and distribution resources. There are three principal applications for distributed generating resources. First, there are large-use customers that may have self-generation opportunities, but still be connected to the grid for reliability and surplus power transactions. Second, there are local installations in existing served areas that are capacity-constrained where a distributed generating resource may be cost-competitive with the cost of additional generation plus a needed transmission and/or distribution capacity upgrade. Finally, there may be remote areas where distributed generation remains cheaper than expansion of the grid.

Large customers with self-generation capability will pursue that option if the cost of grid-supplied energy is excessive and/or there are quality and availability concerns. In general, however, they prefer to rely on the system for reliability services, to supplement their generation at times, and to dispose of surplus generation at other times. If encouragement of this type of distributed resources occurs, the utility system can avoid the cost of new generation, plus the cost of transmission and distribution system upgrades. If this is recognized, and the cost of supplemental service is kept reasonable, a more reliable and diversified power system can result. As discussed below, under Environmental Costing, however, many distributed resources (primarily diesel) have much higher air pollution emissions than central station generating facilities. It is important to evaluate distributed resource options in a manner than takes these costs into account. Using IRP as a tool, a Single Buyer is able to calculate these non-monetized costs along with power supply, transmission, and distribution benefits, and evaluate the desirability of distributed resources.

A utility grid often has localities that are transmission and/or distribution grid capacity constrained. In this situation, it may be more economical to install a distributed generating resource for peak-shaving purposes than to expand central station generation plus transmission and distribution infrastructures to serve a need that exists only a few hours per year. The distributed resource, typically a diesel generator (but sometimes solar, hydro, or other renewable resources), provides supply at the point of consumption, relieving stress on the entire grid upstream of the load. There are both cost benefits and reliability benefits of this approach – even in the case of a complete grid failure, essential loads can still be served from the local generator.

The final area of evaluation for distributed resources is to serve remote areas. Namibia is currently extending grid service to areas not currently served, in some cases displacing existing (diesel) distributed resources. Choosing the best method to extend service involves trading off the cost of extending power lines with the cost of installing local generating resources. In most cases, local generation will be more expensive than central station generation. Even if local renewable energy sources (wind or hydro) are available at costs comparable to central station generation, the reliability services (standby and reserve generation) are a significant cost.

In areas where the cost of transmission and distribution system expansion can be avoided, however, it is probable that there are some opportunities for distributed generation to avoid or delay the need for these additional grid expansion costs. In these situations, grid expansion may prove to be a higher cost alternative than use of distributed resources. An IRP provides the framework for comparison of alternatives, and enables the Single Buyer to choose the best alternative, including consideration of situations where a distributed resource may be more expensive on a generation-only evaluation, but less expensive when compared with generation plus delivery costs.

1.1.7. Risk Management

The single most important lesson of the California energy crisis of 2000-2001 is that energy portfolio risk management is a crucial function, and that some entity must perform this function well, or customers and the regional economy are exposed to significant harm.

Risk management can take many forms, and the best form for Namibia is not evident at this time. One form of risk management is acquisition of sufficient long-term fixed-cost resources that there is little variation in costs; this is essentially the approach taken by Eskom in South Africa, with huge investments in coal-fired generation. Another form is to have an energy portfolio wholly dependent on market prices, and then use financial hedges to stabilize the utility revenue requirement. In between these extreme examples lie most of the preferred approaches: building a diverse portfolio of efficiency and generating resources with different lifetimes, different fixed and variable costs, different fuels, and different sources of volatility.

Attachment E to this report is a recent Regulatory Assistance Project publication on the issue of energy portfolio risk management, setting out the principles and techniques to moderate volatility and preserve the economic benefits of resource diversity. The most appropriate techniques for Namibia will require study and evaluation, but the concept – that a diverse portfolio of environmentally sustainable resources serves to stabilize utility costs and mitigate utility risk – is equally applicable.

The IRP should contain a complete discussion of how the Single Buyer plans to manage its energy portfolio to mitigate risk while taking advantage of market power purchase opportunities.

1.1.8. Environmental Costing

Environmental impacts of energy production include air, water, noise, and land use impacts. No energy resource is completely free of adverse environmental impacts, and every resource should be evaluated in light of the resource-specific impacts that it causes.

Namibia has adopted environmental principles that are second to none in the world. The Ministry of Mines and Energy and the Electricity Control Board[1] both include environmental principles in their Mission Statements. Namibia ratified *the United Nations Framework Convention On Climate Change* in 1995, which calls for signatories to take steps to recognize, anticipate, regulate, and constrain emissions of greenhouse gases.

In the context of the UN Framework, carbon dioxide emissions are the most important to evaluate. Any fossil-fired resource imposes carbon dioxide emissions, with pulverized coal generation being the most serious, and combined-cycle gas being less serious. Most jurisdictions that have attempted to address the carbon dioxide emission issue through regulation have either assigned a specific dollar value to carbon dioxide emissions, or have specified a level of renewable energy development independent of traditional cost criteria. We believe that Namibia should follow one of these two approaches immediately, in order to ensure that major resource decisions are consistent with Namibia's environmental commitment. The best choice should be established in the process of adopting the IRP rule, and the Model Rule presents two alternative approaches for consideration during the rulemaking process.

The IRP should contain explicit environmental costing assumptions. To the extent these are not included in the Rule adopted by the ECB, the Lead Agency shall establish values in consultation with the Stakeholder Advisory Group, subject to a default value specified in the Model Rule.

1.1.9. Industrial Customers Not Taking Retail Service

One important question for Integrated Resource Planning is whether large-use industrial customers who are allowed to access the wholesale market for supply should be subject to the requirements of integrated resource planning. In Namibia, there is at least one industrial customer that is being served directly from the international transmission system, rather than through a Namibian utility.

The approach to this depends, in part on what form the IRP is to take.

If, as is the case in South Africa, a single IRP for the entire country is prepared, then it should include all loads in the country, including those of industrial customers with market access.

Alternatively, if each electricity distributor is required to prepare an individual IRP, then the loads of customers buying directly from the wholesale market will not be included. One option would be to exclude these customers from the IRP process, on the theory that they will manage their own energy use in a manner consistent with their own financial criteria. Another would be to require that each such customer prepare an IRP that

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[1] The "Shared Values" of the Namibia ECB state: *To ensure that the endowment of the energy resources are available to present and future generations*

conforms with the rules, and implement the results of that IRP in a manner consistent with the rules, as a condition of access to the wholesale market.

The Model Rule anticipates a single national IRP that includes quantification of opportunities within the industrial sector.

1.2. Public Process for Planning and Plan Review

Experience suggests that the most successful IRPs are developed with as much input from stakeholders as can be obtained. This input can be encouraged through development of a transparent process that builds respect between the regulator, the utility, and the stakeholders in the process. Our experience has been that collaborative workgroups can help to produce a superior Plan, and ensure that the necessary support for successful implementation of a Plan is present.

For that reason, we recommend that a collaborative stakeholder process be used to develop and review the IRP(s) prepared for Namibia, and that the stakeholders have multiple roles. First, Stakeholders should participate in the drafting of the IRP Rule itself. Second, they should have a seat at the table with the entity(s) preparing the IRP(s) as the Plans are outlined and developed. They should participate with the ECB in evaluating the adequacy of the Plan(s) that are prepared. Finally, Stakeholders should have a role with the ECB in evaluating the progress of Plan implementation.

1.2.1. Process for Consideration of the IRP Rule

The process for consideration of the IRP rule should begin with notification to interested parties of the intent to solicit a rule, following by development and circulation of a proposed rule. Stakeholder workshop(s) should be convened, a draft rule proposed, comments received, and a final rule promulgated.

1.2.1.1. Notice of Intent to Adopt a Rule

The first step should be issuance of a notice of intent to adopt an IRP rule. This would put all stakeholders on notice that this is being initiated, at an early enough stage in the process to allow them to commit the resources needed to participate in the process. The Notice of Intent should be issued during the third quarter of 2003.

1.2.1.2. Circulation of a Model Rule

Concurrent with the Notice of Intent, the ECB should circulate a Model Rule, which could be identical to or different from the Model Rule contained in Appendix A of this Report. The purpose of the Model Rule is to indicate the breadth of the intended rule, and to evoke comment at an early stage of the process on the issues to be addressed by the Rule. The Model Rule should be specific enough that it addresses all issues that the ECB intends to include in the rulemaking process.

1.2.1.3. Issuance of a Draft Rule

Following receipt of written comment on the Model Rule, the ECB should draft a Proposed Rule, and circulate this for examination and comment. The Draft Rule should incorporate all recommendations submitted in response to the Model Rule that the ECB determines will improve the IRP process.

1.2.1.4. Stakeholder Workshop on IRP Rule

Prior to adoption of a final rule, the ECB should convene a Stakeholder Workshop on the IRP rulemaking. This would be an opportunity for all stakeholders to interact with one another, with the ECB staff, and with the Board on the content of the Rule. By delaying the Stakeholder Workshop until after the close of at least one round of written comment on the Draft Rule, the positions of stakeholders will be known, and the parties can have a meaningful discussion on the merits of each recommendation.

1.2.1.5. ECB Adoption of IRP Rule

Finally, the ECB should adopt a formal rule, including such modifications from the Draft Rule as it determines are appropriate. Final adoption should take place during the first quarter of 2004.

1.2.2. Process for Development of the Plan(s)

Following adoption of the IRP rule by the ECB, the process of plan development will begin. This report is drafted based on the assumption that the final rule will call for a single national IRP, similar to that in South Africa, developed by the Ministry in cooperation with NamPower and local distributors. In the event that the ECB determines that individual load-serving entities should prepare individual plans, the concepts reflected in the text will need to be interpreted consistent with that approach.

The IRP development process should be open, collegial, and collaborative. If the stakeholders develop a sense of intellectual competency and professional respect, it will be more likely that the result of their collaboration will be a Plan that all parties can support.

1.2.2.1. Establishment of Advisory Groups

Early in the Plan development process, the ECB shall establish a Stakeholder Advisory Group (SAG) or groups to assist and collaborate in the development of the Plan. The SAG shall include representatives of all customer groups, including residential consumers, low-income organizations, the commercial (retail and office) sector, and the industrial sector. It shall also include federal and municipal representatives, and experts from the energy efficiency and energy supply industries. The intent is for the SAG to be broad enough that all relevant non-utility perspectives are adequately represented. Interested parties shall apply to the ECB for appointment to the SAG. All entities that the ECB judges may make a meaningful contribution to the process shall be encouraged to participate in the SAG.

The SAG will have responsibilities to inform the planning process, to review the expertise of consultants and staff retained to work on the Plan, to review drafts of sections of the Plan as they are developed, and to comment to the ECB as appropriate as the Plan development moves forward. The SAG shall be accorded formal status as a participant in any ECB proceedings that may be convened to review and consider approval of the Plan.

The SAG should be appointed concurrently with the adoption of the Final Rule

1.2.2.2. Identifying Experts to Prepare Plan Sections

The Plan shall address all of the elements required by the Rule, and it is not likely that all elements of this can be prepared within the existing expertise of NamPower. The SAG shall have a leading role in advising on the issues to be addressed by NamPower staff and consultants, and in evaluating the expertise of proposed consultants to work on sections of the Plan. If the SAG does not concur with NamPower, it shall have the option to petition the ECB to intervene and rule on the selection of experts from within and outside NamPower assigned to develop the sections of the Plan.

1.2.2.3. Completion of Technical Studies

Technical studies on the demand forecast, availability of supply-side resources, availability of demand-side resources, and evaluations of the alternative institutional structures to achieve demand-side and supply-side resources are the first building blocks of a successful Plan. The SAG will be involved throughout the development of these technical studies, from the specification of the elements of each study and the selection of staff and/or consultants to prepare the technical studies, to the evaluation of the results of the studies. The use of SAG subcommittees may be appropriate to monitor individual technical studies as they progress.

1.2.2.4. Initial Draft Preparation

Once the technical studies are well underway, preparation of an initial draft of the IRP will commence. NamPower will have primary responsibility for this, subject to review as each section by the SAG or its subcommittees. The Draft preparation should be a collaborative effort, with input from the SAG encouraged at every step.

1.2.2.5. Stakeholder Advisory Group Review

Once a complete internal Draft has been prepared, the SAG should review the entire document for consistency with the Rule, for completeness on important topics, and for fairness in addressing multiple perspectives. Once the SAG agrees, the document should be released for public review. If the SAG and NamPower cannot agree, the ECB may be asked to intervene and rule whether a Public Review Draft should be released, or additional analysis undertaken prior to such release.

1.2.2.6. Public Review Draft

The Public Review Draft will be a draft-final IRP, containing all of the elements required by the Rule, reflecting the work of all technical studies identified as important through the Plan development process, and containing an Action Plan for implementing the Plan. It is this document that Stakeholders and other members of the public will refer to in preparing comments to the ECB regarding acceptance of the Plan.

1.2.2.7. Comment Period

The ECB will establish a reasonable comment period on the Public Review Draft, taking into account the complexity of the document and the need for expeditious review in order to move to implementation. A 60-day comment period, with an open session to discuss Plan elements, will meet this requirement.

1.2.2.8. Commission Evaluation Process

Following the comments on the Public Review Draft, the ECB shall evaluate the Public Review Draft and the comments received, and render an Order accepting the Public Review Draft, or requiring NamPower to make changes to the Draft prior to acceptance. In most cases, it is anticipated that the Public Review Draft will be accepted, and guidance will be provided for changes to the subsequent IRP development. In some cases, the Public Review Draft may be remanded to NamPower with specific guidance for changes based upon the comment received.

1.2.3. Consequences for Non-Compliance

In the event that NamPower does not comply with the terms of the IRP rule, some consequences must result.

First, there should be a rebuttable presumption that resources acquired that are consistent with an accepted IRP are appropriate, subject to review for prudence. Similarly, resources acquired that are not consistent with an accepted IRP, or when there is no IRP, there should be a rebuttable presumption that the resources acquired are not prudent, and each resource acquisition should be examined in detail for prudence.

1.2.4. Funding Participation In the Process

Some stakeholders will not have the funding to participate in the process without assistance. In some cases, this may be as simple as providing travel and communication assistance, and in others, it may be necessary to fund the expertise for stakeholders to participate.

A principle of the IRP rule should be that no meaningful stakeholder contribution to the process should be excluded for lack of financial ability to participate in the process. As a practical matter, however, the resources available for this process are limited, and the total amount of funding for stakeholders should not exceed a reasonable fraction of the total cost of preparing the IRP. NamPower shall propose to the ECB a process for requesting Stakeholder Funding prior to the date for release of the Draft Rule, and the ECB shall include a process for Stakeholder Funding in the Draft Rule.

NamPower is responsible for ensuring that all stakeholders have an adequate ability to participated, and to provide funding as needed. In the event of a disagreement, the ECB may be called upon to mediate or resolve stakeholder participation issues. An application for Stakeholder Funding that is denied by NamPower shall be reviewed and resolved promptly.

1.3. Implementing the Plan

Once a Plan is adopted, implementation is largely the responsibility of the Single Buyer, but some resources are best achieved through acquisition mechanisms that involve actions by other parties.

The ECB will monitor Plan Implementation, and apply appropriate guidance to NamPower, local distribution utilities, and other Stakeholders as needed.

1.3.1. Resource Mix and Portfolio Management

The resource portfolio acquired by Namibia utilities is the single most crucial element of assuring an adequate, reliable, and economical electricity supply for Namibia. The portfolio consists of existing resource, new long-term resources, various short-term operations, and a risk mitigation strategy to deal with cost volatility. Both the long-term and short-term resources include a mix of supply-side and demand-side opportunities, and optimizing this mix is the essential role of the Single-Buyer portfolio manager.

1.3.1.1. Existing Resources

Namibia's existing resources include hydro, coal, diesel, access to Southern African power Pool through the Short Term Electricity Market, and bi-lateral purchase arrangements with Eskom. The last of these is scheduled to decline and/or end in the future, and a great deal of the work required by the IRP process will focus on how best to replace these purchases at the end of the current agreement.

The IRP will assume that existing resources that do not require major maintenance work will remain a part of the energy supply system. Those which do require reconstruction, refurbishment, major pollution control investments, or have expiring fuel supply arrangements should be treated in the same manner as potential new resources – with the decision on major investments determined by the value of the resulting resource in comparison with other alternatives.

1.3.1.2. New Long-Term Resources

A wide variety of potential new long-term resources have been examined by NamPower and by MME. These include the proposed combined-cycle unit in conjunction with development of the Kudu gas field, wind resources along the coast, and small hydro developments on the Orange River. In addition, there are long-term resources available in the form of energy efficiency investments, system efficiency investments (e.g., voltage upgrades), and distributed generation.

Long-term resource acquisition requires a higher degree of creditworthiness. Ascertaining whether it is economical or desirable to strengthen Namibia's power sector balance sheets to support long-term resource acquisitions is a complex undertaking, best approached in the context of an IRP, where the alternatives are also being examined.

The framework for evaluation of alternatives must consider the size and character of the resources, reserve requirements, cost of integration into the existing grid, transmission impacts, and other factors. Because of the "lumpiness" of the Kudu resource and the imminence of the Kudu decision, it is crucial that a thorough examination of alternatives begin at the earliest possible time to inform that decision.

1.3.1.3. Short-Term Operations

All utilities engage in short-term operations for load balancing, load shaping, dealing with outages, seasonal diversity, and other factors. Namibia is no exception to this.

There are at least two separate issues relating to short-term operations to be examined in the context of an IRP.

First, the level of short-term operations directly affects the level of volatility in power costs. As Namibia's longer-term fixed-price contracts with Eskom ends later in this decade, the national economy will be exposed to greater and greater amounts of short-term power purchases. Determining the optimal level of short-term purchases requires some risk management analysis, discussed below. Second, many analysts have concluded that short-term markets, over time, are less expensive than long-term resource acquisitions, and have recommended a high degree of reliance on market-based pricing, rather than the cost-based pricing that typically accompanies long-term resources.

1.3.1.4. Fuel and Market Risk Mitigation

If Namibia relies on short-term markets for much of its power supply, it is exposed to one form of volatility, related to the power it requires. If, instead, it builds large fixed-cost resources, such as Kudu, it will have surplus power to sell many hours of the year, and will be exposed to volatility in its revenue stream.

The presence of a large seasonal hydro resource in Namibia creates fuel and market price risk as well. During the wet season, Namibia is a power exporter in many hours. During the dry season, it is a power importer. The trading partners in Southern Africa have very different weather and hydro conditions than Namibia; for example, Eskom is also interconnected with the large hydro resource of Mozambique, which has a completely different annual and seasonal output pattern to the resources in Namibia.

If Namibia relies on oil-fired resources, including distributed resources that mitigate transmission and distribution investments, it is exposed to oil price risk. If it relies on wind generation, the non-dispatchable nature of this generation creates market price exposure.

There are many tools to manage and mitigate risk of this type. The Regulatory Assistance Project report on Portfolio Management addresses many of these issues in detail. This report, contained in Appendix E, identifies many key cost volatility issues.

The IRP needs to include a significant section on Portfolio Management, addressing how Namibia will address the fuel and market price risk of various alternative resource strategies.

1.3.2. Form of Supply Acquisition

The manner in which electricity supply is acquired can affect the stability of supply, the cost of supply, and the duration of a resource. Where utilities own their resources, the costs tend to be more predictable. In the Single Buyer model, however, it is anticipated that the utility will acquire substantially all new resources from Independent Power Producers (IPPs). The Integrated Resource Plan needs to consider the form of acquisition in the context of the predictability and level of utility cost.

For any major resource acquisition, the IRP should require that the alternative forms of ownership be compared on a resource-specific basis. In this manner, the trade-off between ease of acquisition and stability of cost can be objectively analyzed.

In Namibia there seems to be an expectation that new large-scale fossil-fired generating facilities will be constructed by IPPs. It is important to recognize that the utility will have a different capital structure and cost of capital than an IPP will, and that this will affect the cost and cost-effectiveness of certain types of resources. It is possible that the form of ownership will influence the determination of the most cost-effective resource mix. For this reason, it is essential that the IRP framework clearly provide for differential capital costs by ownership form, and for the calculation of resources costs based upon ownership-specific costs of capital.

1.3.2.1. Utility-Owned Resources

Historically, vertically integrated utilities built and owned their own generating resources. In Namibia, the Windhoek generating station and the hydroelectric facility on the Kunene River are examples of this form of development.

This form of ownership is still appropriate for a number of different types of resources. System efficiency improvements are the obvious example: investments in higher efficiency distribution systems, improvements to existing generating facilities and improvements in the efficiency of utility-owned buildings.

One principal advantage of utility ownership, particularly of long-lived resources such as coal and hydroelectric facilities, is that the units can typically be rebuilt and renovated for a fraction of the cost of new construction. With life-extension, the end-effects of such resource can be very important in the long run. The treatment of long-lived resources in an IRP is very important; if the analysis is for a shorter period that the life of the longest-lived resource alternative, some sort of end-effects modeling must be incorporated or the shorter-lived resources will have an inappropriate analytical advantage.

1.3.2.2. Competitive Bidding

Where the IRP indicates that a generic form of resource is the most attractive alternative, the resource can be acquired either through direct utility ownership or by soliciting IPPs to construct the resource. In the latter case, competitive bidding is the traditional approach to acquiring resources from IPPs.

Appendix B contains the Competitive Bidding rule adopted by the Washington Utilities and Transportation Commission (WUTC). The WUTC requires all utilities, upon filing their Least Cost Plans (functionally the same as an Integrated Resource Plan), to open a competitive bidding process for new resources. In a situation where the utility has a surplus, the prices they are willing to pay are suppressed, but in all cases, a competitive solicitation is opened.

Competitive bidding is an attractive way to provide incentives for ingenuity in electricity supply. The Namibia IRP process should encourage competitive bidding for those types of resources for which private-sector development is the most attractive alternative.

Competitive bidding can take several forms. IPPs can bid on the right to supply power, from resources they build and own. Out-of-area power sector participants, such as Eskom, can bid on the right to supply power from new and/or existing resources. Energy efficiency contractors can bid on the right to supply negawatts from new and/or existing facilities they will modify.

Most IPPs engaged in competitive provision of power retain ownership of their resources. This creates a finite term to the power supply – the length of the contract offered. Competitive bidding can also be turnkey – with the vendors competing to build a resource that they will then turning over ownership and operation of to the utility acquiring the resource. In this situation, if the resource life exceeds the contract life, the utility gets what are known as *end-effects* benefits. It is important for the IRP to carefully measure the end-effects benefits of resources that have expected lifetimes longer than an initial contract term, depending on what entity retains those benefits.

Competitive bidding for energy efficiency resources will be discussed below.

1.3.2.3. Distributed energy systems vs. grid expansion

Distributed energy systems perform multiple functions. If they substitute for expansion of transmission and distribution facilities into remote areas, they obviate the need for and cost of those facilities, as well as generation needs. If they are located in areas already served, but where capacity constraints are forecast, they similarly avoid generation, transmission, and distribution capacity costs.

The IRP should specifically identify all localities where grid expansion is contemplated during the period of the Plan --at least five years. In each situation, the avoided cost of grid expansion should be compared with the cost of distributed resources.

One benefit of distributed energy systems is that they may bring electrification to a new area, and jump-start the local economy. As a local economy expands, and electric demand increases, it may become cost-effective to expand the grid. This is the approach used extensively in Indonesia, where there are several hundred non-integrated electric systems. When grid expansion becomes cost-effective to a recently electrified area, the diesel generators are moved to a new location, and the cycle begins again.

1.3.3. Form of DSM Acquisition

The means by which energy efficiency resources are acquired can significantly affect the cost of those resources. The IRP needs to compare the alternative methods by which efficiency can be acquired, and then evaluate the cost-effective resource based on the most economical means of acquisition.

1.3.3.1. Utility-managed

Most utility-operated DSM programs are administered by the utility, through independent installers. The utility pays all or a portion of the cost of a measure, and the installer works with the end-use consumer in a customer-service capacity.

The advantage of this approach is that the utility retains quality control and involvement, reaps the customer relations benefits that the programs generate, and can target programs to precisely the areas where they offer the best transmission and distribution system benefits.

1.3.3.2. Competitively Bid

Some utilities have attempted competitive bidding of efficiency services. The Washington rule, included in Appendix B, requires this option, with efficiency bid on a competitive basis with other resources.

One advantage of this approach is that vendors find much cheaper ways to deliver efficiency service. One negative is that it provides a strong incentive for cream-skimming programs that may make it impossible to acquire all cost-effective efficiency measures over time.

The IRP should examine competitive bidding for efficiency measures, subject to the constraint that the bidding mechanism retain incentives for pursuing all cost-effective measures and concentrating efforts on localities with the largest benefits.

1.3.3.3. Separate Entity – Efficiency Vermont

The state of Vermont has taken an innovative approach to encourage effective acquisition of efficiency resources by creating a separate "Efficiency Utility" which invests statewide in measures to improve the efficiency of energy use. Efficiency Vermont operates statewide and regional programs where the measures are best achieved through consistent program offerings. In cooperation with local distribution utilities, many in very rural areas, it provides focused incentives in areas where efficiency savings brings transmission and distribution benefits.

The advantage of a separate entity is that it has a single mission: efficiency. It is not discouraged by impacts of efficiency on utility revenues, or by perceptions that a "bigger" utility is "better" utility.

Efficiency Vermont is funded by an assessment on all distribution utilities in the state. The program is administered by a non-profit non-governmental organization. It has been awarded a multi-year contract, approved by the state Commission, and reports to the state regulatory commission in the same manner as any other utility. It is accountable for the prudence of its expenditures, and evaluated based on its performance.

The IRP should contain an examination of whether the barriers to utility achievement of efficiency goals are present in Namibia, and whether creating a separate entity to acquire energy efficiency is appropriate for Namibia.

Appendix F contains a recent Annual Report from Efficiency Vermont describing how this entity operates.

1.3.3.4. Codes and Standards

Building codes and appliance efficiency standards are a means to achieve many energy efficiency goals without a requirement that the utility or utility ratepayers fund programs to acquire these resources. Basically they are coercive, rather than incentive mechanisms.

In general, codes and standards are much more reliable means to achieve higher levels of efficiency at lower costs than are incentive programs. This is because the administrative costs are much lower, and the participation rate is much higher. However, building officials often do not consider energy efficiency to be their responsibility, and without vigorous enforcement, compliance may be low.

Many countries have adopted and implemented building code standards and appliance efficiency standards. The results of these programs have been very positive. One interactive benefit: if the primary appliance desires in remote, rural, low-income areas are lighting, refrigeration, ceiling fans, and television, aggressive codes and standards may keep demands low enough that distributed resources, rather than grid expansion, is the most economical way to extend service.

Experience in many places has shown that the transition to new codes and standards can be eased dramatically by including incentives for at least a short period, until builders and building operators become comfortable with the new technologies. One form of incentive may be financial, while another form may be simply to provide design assistance, code enforcement training, and code enforcement technical assistance.

The IRP should examine the applicability of energy efficiency codes and standards in Namibia, and identify the techniques and costs needed to achieve a high degree of efficiency achievement through aggressive pursuit of cost-effective measures that properly should be included in the new building and new appliance market.

1.3.4. Periodic ECB Review of Implementation Progress

Once a Plan is accepted by the ECB, it is critical that the Board monitor the progress of the utility system at achieving the resource priorities identified in the Plan.

Initially, the ECB should require quarterly reporting on the status of resource acquisition under the accepted Plan, and the status of technical studies and the evaluation process for the next Plan cycle.

The Model Rule provides for periodic reporting to the ECB by all entities with obligations to implement elements of the IRP.

1.4. Implementation Schedule

The Implementation Schedule set forth below is intended to result in a completed IRP by the end of 2004, so that NamPower can begin meeting its obligations as a Single Buyer in an informed manner. During the period prior to ECB acceptance of the IRP, NamPower should be required to obtain explicit approval from ECB before entering into any contracts that exceed 5% of its demand and have a term of more than 5 years.

Implementation Schedule

Draft Report on Single Buyer Issues	July, 2003
Notice of Intent / Release of Model Rule	August, 2003
Comments Due on Model Rule	September, 2003
Draft Rule / Initiation of Rulemaking	October, 2003
Stakeholder Process on Rulemaking	December, 2003
Adoption of Final IRP Rule	February, 2004
Creation of Stakeholder Advisory Group	March, 2004
Technical Studies Completed	August, 2004
Draft IRP Submitted for ECB Review	November, 2004
ECB Decision to Accept or Remand IRP	December, 2004

1.5. Reference Material for this Section

Examples of Integrated Resource Planning Rules; Oregon, Washington

South Africa IRP Framework

South Africa IRP, 2002

Portfolio Management, Regulatory Assistance Project

Annual Report, Efficiency Vermont

2. The Obligation to Serve in Namibia

2.1. Background

Many countries have taken steps to restructure their electricity industries in recent years. All of them have mauled over the vexing question of who will make sure that there is sufficient generating capacity to meet future demand.

From the outset, we wish to make it clear that under all forms of industry restructuring the Government remains ultimately accountable for the supply of electricity to its citizens. Recent experiences in liberalised electricity markets - notably California and Ontario - have proven that when there are serious supply (or price) concerns, Governments are expected and will intervene to arrest the situation. However, under normal operating conditions, the general trend is for Governments to delegate this responsibility to organisations that are better equipped to deal with making sure there is adequate electricity supply. Industry reforms require Governments to re-visit this important delegation of responsibility.

Before discussing the options in more detail, it is necessary to define some of the important terminologies to prevent any misunderstandings. In particular, there are two terms, which have lead to considerable confusion in the past. For the purpose of this memorandum, they are briefly defined as follow:

- ***Obligation to Supply***: It implies the responsibility to decide when new generating plant is built and what type of technology will be used. It generally also includes the responsibility to build, operate and maintain the plant.

- ***Supplier of last resort:*** This only entails the task to build, operate and maintain the plant on the instruction of another authority. There is an important difference in that the supplier of last resort does not make the decision when to build.

2.2. Present Situation

Namibia's electricity industry is currently structured along the lines of a vertical integrated monopoly utility (NamPower) that is responsible for generation (100%), transmission (100%) and distribution (< 100%).

It is important to point out that up to 2000, NamPower carried the obligation of supply responsibility in Namibia. The utility essentially decided what options are required to meet the country's electricity supply needs. Although NamPower has never made a decision to build a new power station, it has deliberately made the decision not to build it but to rely on imports to meet its growing demand for electricity. Up to this point

NamPower was the organisation that decided if a new generating plant was needed. They would also have built it if it were necessary.

Soon after the establishment of the Electricity Control Board (ECB) in Namibia all existing and new generating companies were required to hold a valid generating license from the ECB. In other words unless the ECB agrees, no new power stations could be constructed in the country. This means that the ECB has taken over the responsibility to make the decision on when new plant is required and what type it should be. At the moment, the necessary structures don't exist to permit Independent Power Producers onto the system and therefore it is safe to assume that NamPower is considered the supplier of last resort.

Given the small size of Namibia's electricity industry the separation between obligation to supply and supplier of last resort is somewhat blurred. In practise, it means that both ECB and NamPower will consult with one another on the demand and supply situation in order to get a full picture of when new supplies are needed and what type of plant is required.

2.3. Single Buyer Market

Under a Single Buyer (SB) market arrangement it would be possible for IPP's to construct new plant in Namibia. This development would require a more clear separation between obligation to supply (primarily the decision on when to build) and the supplier of last resort (who will be instructed to build new plant if nobody else wants to).

Considering that NamPower (Generation) is a potential competitor in the market for new generating capacity it would not be prudent to consult with them on the need of new plant or when the ECB receives an application for a generating license from a potential competitor.

On the other hand, the Single Buyer will have detailed information about the demand and supply situation in the country. As such, it is in an ideal position to provide support to the ECB in terms of identifying the need (timing and type) of new generating capacity for Namibia. Consequently, the obligation to supply in a Single Buyer market would rest with the ECB. In turn, it is expected that the ECB will work closely with the SB to monitor the future supply and demand balance.

Although difficult to foresee how it could happen a situation may arise that no generating company [including NamPower (Generation) and IPP's] is willing, despite the best efforts of the ECB and SB, to build new plant. Under this condition, the ECB may decide to instruct NamPower (Generation) – as the supplier of last resort – to build new generating capacity.

From the above discussion, it is clear that the introduction of a Single Buyer Market in Namibia will result in the shifting of responsibilities between the different players to ensure that Namibia has access to sufficient generating capacities to meet its future demand requirements. It is expected that these shifts will occur gradually over time rather than as a sudden once of occurrence.

3. Challenges to Implementing A Wholesale Market Structure in Namibia

Some energy market observers in Southern Africa might question the implementation of integrated resources planning on a national level, instead preferring to focus on the establishment of a competitive wholesale market to improve electricity market efficiencies. This view assumes that a viable wholesale market is viable for Namibia, and that a competitive wholesale market can achieve all of the benefits that are expected from a rigorous IRP process. As we discuss below, these assumptions are not necessarily reflective of current or potential conditions in Namibia.

3.1. Lack of a Viable Wholesale Market in Southern Africa

In order for a wholesale market to be viable, there must be a large numbers of buyers and sellers in the market, none of which are large enough to exert market control. Currently, approximately 80% of the electricity generation in Namibia is controlled by Eskom. The remaining market participants are all comparatively small. Most operate very few generating facilities, and are therefore not able to offer the kind of reliable service from a diverse portfolio that would make them viable competitors to Eskom. Any purchase of power from a seller operating only a few resources would require separate purchase of reliability services (spinning reserve, operating reserves, load following, and other ancillary services), probably from Eskom.

If Eskom were broken up into five or more separate generating companies (as has been discussed) and if the generating facilities of neighboring countries (Mozambique, Zambia, Zimbabwe, Angola, DRC, etc) were all able to move freely through a reliable transmission grid to Namibia, it is probable that a viable wholesale market could evolve in Southern Africa. This is, at best, many years away.

Until the wholesale market evolves to the point where all needed services are available from multiple sellers on a competitive basis, it cannot be asserted that a viable wholesale market exists in Southern Africa.

3.2. Small Size of Electric Loads in Namibia

The total national load of Namibia is less than the output of a single new economic-sized generating facility. The potential new generating facilities in Southern Africa include new large hydro projects in the 1000+ megawatt range, new coal-steam units in the same general size range, and new combined-cycle generating facilities in areas where natural gas is available. Even these natural gas units are most economical in the 400 mw to 800 mw size range. The individual loads of the Namibia Regional Electricity Distributors will be in the 50 mw to 150 mw range. As such, none would be able to enter into a contract for more than a small percentage of the output of a new economically-sized generating unit. If and when there are multiple sellers willing to offer economical and reliable power supplies to customers of this size range, then the REDs may be able to become effective market participants. That opportunity is, at best, several years in the future.

3.3. Wholesale Markets Do Not Address Energy Efficiency or Distributed Resources

The IRP process discussed in this report addresses not only supply-side resource acquisitions, but also demand-side acquisitions and distributed resources.

Wholesale electric power markets do not address cost-effective energy efficiency measures very effectively. The market barriers to efficiency have been well-documented for many years, and there is little reason to believe that those barriers will be less severe in Southern Africa. [See, especially, Profits and Progress through Least Cost Planning, provided in the reference material to this report.]

Distributed generating resources, primarily renewable resources are an important opportunity for Namibia, particularly in the remote areas of the country. There are similar obstacles to the implementation of renewable resources, and a comprehensive IRP approach can identify these barriers, and solutions thereto. [See, especially, Renewable Energy: Barriers and Opportunities, in the reference material to this report.]

The cost of upgrading transmission facilities to deliver power to (or import power through) Caprivi, for example, are the types of decisions that wholesale markets can only provide a portion of the needed information. The alternative, developing local generating resources, and leaving these areas isolated, may be desirable or undesirable. Only a comprehensive review of national opportunities, priorities, and costs can effectively compare such alternatives. [See, especially, Efficient Reliability, provided in the reference material to this report.]

3.4. Limited Capabilities of the Regional Electricity Distributors

A final challenge to the establishment of a wholesale market structure in Namibia is the limited professional and technical capabilities of the newly formed Regional Electricity Distributors. These new institutions are initially primarily concerned with upgrading and maintaining distribution infrastructure, and do not have the skills needed to engage in wholesale power market purchasing. While that set of skills may be available in the future, and the REDs may be able to take over the wholesale power acquisition function in a few years, that capability does not exist today. As discussed later in this report, however, many of the REDs will have loads that are so small that it may not be practical for them to develop this professional capability unless and until their loads (and associated revenues) grow substantially.

Until then, the Single Buyer + IRP structure is likely to be the most efficient, economical, reliable, and certain structure for providing wholesale power to the REDs.

4. Steps to A Wholesale Market Structure

The purpose of this section is to discuss the various steps that would need to be taken to move from the Single Buyer market structure to a Wholesale market structure. In this context, the term "Wholesale Market Structure" means that the (five) Regional Electricity Distributors would generate their own power and/or purchase their own power supplies in the wholesale market, independent of each other. This is contrasted to a Single Buyer structure, in which NamPower serves as the power supply portfolio manager for all of the regional electricity distributors, or to a Retail Access structure, in which individual consumers (residential, commercial, and industrial) would directly arrange for their own power supplies by purchasing from competitive retail suppliers.

4.1. The Creation of Five Regional Electricity Distributors

Government policy, of which the Ministry of Mines and Energy is the custodian, calls for the large number of distributors of electricity (approximately 42) should be consolidated into five regional electricity distributors (RED's). The five distributors will be regional and will each distribute in the respective geographic areas.

These RED's will each initially buy electricity from the transmission business unit of Namibia Power Corporation (Pty) Limited (NamPower) to distribute and supply to customers in a captive geographic area. However, the transmission business unit of Namibia Power Corporation (Pty) Ltd. will continue to supply electricity directly to a number of large customers to whom electricity is supplied at high voltage like mines and other large uses that are directly connected to the NamPower transmission network. In terms of the current arrangement within NamPower the generation sells all electricity it generates to the Single Buyer, which is a business unit within NamPower. Eventually it is the transmission business unit that sells to all transmission customers including the RED's.

As the maximum demand of the country is about 350 MW the capacity of the five RED's will very from a maximum of 120 MW for the biggest RED to approximately 30-40 MW for the smallest RED. In other words most of the RED will have relatively low levels of maximum demand. Under a wholesale market system each RED and other contestable large customers will have to directly participate in the market by buying directly from generators. The role of the Transmission business unit of NamPower will be to limited to wheeling the electricity on behalf of the RED's and serving large users that secure their own power supply in the wholesale market.

However since the only generator currently dispatched by NamPower is Ruacana, which has capacity of 249 MW the rest of the electricity needs of the country are provided for by means of imports from Eskom (Pty) limited in South Africa. NamPower currently has the sole right to import electricity from South Africa. Unless more generation capacity with competitive costs is constructed inside the borders of Namibia the country will never have sufficient number of generators to be either self-sufficient or a significant participant in a competitive and efficient wholesale market. Since Ruacana is a business unit within NamPower it will also not be in a position to effectively participate in a market system unless it operates as an independent subsidiary of NamPower.

If no additional generation capacity is build within the borders of the country it can utilize imports from South Africa or other SAPP nations, as the current cross-border transmission infrastructure has the capacity to transmit at least 600 MW. Currently the total installed capacity in South Africa is 40,000 MW, meaning Namibia's total consumption is about 1% of total installed capacity in South Africa.

South Africa is also in the process of reforming its electricity sector with the aim of creating a wholesale market system. Should Namibia still be a net importer by the time the wholesale market in South Africa is created, the country inevitably would have to participate in such a market. It would then be up to the country to decide whether it of greater financial benefit to the participate in the wholesale market as one institution represented by the Single Buyer, or to allow the relatively small RED's and large customers to each participate in a much larger wholesale market. However should any RED or large customer choose to directly participate in the market it will require highly skilled human resources and well as financial resources to back its position. Each contested would also be required to take all risk associated with direct participation in a wholesale market.

4.2. How Do We Determine If There Is a Viable Wholesale Market?

The most critical element of a viable wholesale market is that there are a large number of knowledgeable buyers and a large number of knowledgeable sellers, none of which is large enough to exert market power. One indicator of success in this regard would be a sustained pattern of wholesale market prices that were close to[2] the short-run marginal cost of the marginal dispatched unit across many load conditions. At the present time, with Eskom controlling a majority of the generation in Southern Africa, it is clear that a viable wholesale market has not evolved to date.

4.2.1. Breakup of ESKOM into smaller entities

One indicator of the creation of a more viable wholesale market would be the breakup of the Eskom system into multiple generating companies, and multiple power distribution companies. The former is necessary as an initial step towards having multiple sellers in the market, and the latter to achieve the necessary goal of having multiple buyers in the market.

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[2] Market monitors often look for a spread of no more than about 10% between short-run marginal costs and wholesale clearing prices. In a perfectly competitive market, price would be driven to marginal cost. However, electricity markets are not perfectly competitive, and system reliability requires "surplus" generation capacity. Thus, it is reasonable to expect generators to seek to recover some portion of fixed costs in the wholesale energy market.

Eskom currently controls about 85% of the generating capacity in Southern Africa. Recent discussion has focused on breaking Eskom into four or five separate entities. Even at this level of fragmentation, each entity would control more than 15% of the generating capacity in Southern Africa and serve more than 15% of the load in Southern Africa. This does not meet a reasonable test of reduced concentration. A better model is the Argentina power market, in which more than two dozen generation companies compete, with the largest company having less than 15% of the total generation capacity.

If, over a period of many years, independent power suppliers in Southern Africa supplied new generation, the market share of the Eskom units would decline. It is possible that each of the Eskom spin-off units would see its market share decline below the 10% level that might lead to a plausibly competitive wholesale market.

4.2.2. IPP and SAPP access to transmission system into Namibia

Another element that would enhance the evolution of a competitive wholesale market would be greater interconnection of transmission into Namibia from countries other than South Africa. In particular, the proposed interconnections from DRC into Angola and thence to Namibia, and from Zambia through Botswana into Namibia would enhance access of Namibian regional electricity distributors to alternative sources of supply.

The adoption of firm market rules within SAPP would be essential elements of an evolving wholesale market structure. These must provide, at a minimum, for full and immediate public disclosure of all transactions (similar to stock exchange rules), for specific assignment of reliability responsibilities for all sellers, and for non-discriminatory access to transmission for all market participants The section of this report addressing Market Rules sets this forth in greater detail.

4.2.3. Separation of NamPower Generating Units into Separate Sellers.

One option that has been discussed would be the separation of NamPower generating units into separate sellers in the marketplace. If this were done, the Ruacana generating station, the Windhoek generating station, and the Walvis Bay diesel unit would be spun off into separate corporate entities, left to compete with one another.

During the California Energy Crisis, it was suggested that holding electricity generators to ownership of a single generating station would have eliminated the risk of "strategic withholding" of capacity that was identified as a significant source of upward price pressure. The theory has been that if each generating unit had a different owner, there would be no risk of strategic withholding of capacity. The suggestion to separate NamPower's generating facilities into separate ownership units appears to rely on similar logic.

Elsewhere in this report in the discussion on Market Rules and Market Monitoring, we recommend that the ownership of a single seller needs to be no more than that the reserve capacity of the power pool of which they are a part (about 10%). This is intended to be smaller than the typical reserve margins that the system needs to maintain for reliability purposes. This, however, is a percentage measured against the combined capacity of

SAPP, not the capacity of an individual country within SAPP. If no seller controls a larger amount of capacity than the system reserves, it is unlikely that any will be able to exert market power.

Conditions are very different in California and in Southern Africa. The concern in California was that individual owners controlled 3,000 to 5,000 mw of generating capacity, enough that during drought conditions, they could exercise market power by strategic withholding. The individual generating units in California were often in the 500 mw to 1,000 mw range. The total combined capacity of NamPower's facilities are smaller than the capacity of a single unit in California. Namibia's concerns should be viewed in the context of Southern Africa, as a competitive wholesale market must evolve through the SAPP region, not just in Namibia. Here, Eskom is the key element for comparison.

The combined generating capacity of Namibia is significantly smaller than the capacity of a single generating unit at one of Eskom's many multi-unit generating stations. Eskom's combined capacity of 42,000 mw dwarfs that of Namibia. Even with a division of Eskom into five separate companies, the average capacity would be about 8,000 mw, or about twenty times the combined capacity of all NamPower units.

Similarly, the current hydroelectric station in Mozambique, Cahora Bassa, has a potential capacity of 4,000 mw. There are additional generating sites along the Zambezi in Mozambique with similar potential capacity. These facilities also dwarf the combined capacity of all electric generating facilities in Namibia.

If anything, it would appear that retention of the consolidated ownership of Namibia's generating facilities might be important to allowing those units, as a whole, to function in an effective manner in competition with larger systems in South Africa and elsewhere within SAPP. Dividing ownership of a small amount of generation among separate entities would be meaningful for the 42,000 mw of Eskom generation, but not for the small amount of generation controlled by NamPower.

4.3. Creation of 5 Distributors: Will They Be Large Enough To Be Effective In A Wholesale Market?

Namibia has been discussing the concept of reorganizing its existing mix of NamPower-owned and locally owned distribution systems into five regional electricity distributors.

This issue deals with whether the five regional electricity distributors will be large enough to effectively function in a wholesale power market environment. Recent examples in both the USA and in New Zealand may be good models for examining this question.

In the Northwest portion of the USA, the Bonneville Power Administration (BPA) provides wholesale electricity to some 100 separate distribution utilities, some of which own generation as well. For the vast majority of these utilities, BPA functioned as a single-buyer. Since 1980, these utilities have become increasingly skeptical of BPA's ability to effectively manage acquisition of new power supplies to meet the growing needs of its utility customers. This discussion has divided along size lines – those utilities with demands in excess of about 250 mw have almost all urged that BPA discontinue its acquisition function, leaving this to the individual utilities to manage their wholesale acquisitions. Conversely, those utilities with demands lower than 50 mw have insisted that BPA retain an acquisition and portfolio management role to meet their needs. The utilities with demands in the 50 – 250 mw range have been divided in their opinion. . In other areas of the United States, smaller utilities often band together in "joint action" agencies to manage jointly all or a portion of their power portfolios.

In New Zealand, two decades ago, a single-buyer federal power supplier delivered wholesale power to some 54 local distribution utilities. Several stages of restructuring, privatization, and reorganization have occurred. The rural areas of New Zealand have been most adversely affected by this, simply because the ability of these small distribution companies to function effectively in a wholesale market (and retail access structure) has been less than successful. Prices have increased, and reliability has decreased.

The lesson from these two experiments seems to be that larger utilities (those over 250 mw) can function effectively in a wholesale market, but smaller ones are less likely to be successful unless served by a joint action agency or a larger single buyer.

The Namibian system is characterized by several large mining installations that use about half of the country's power consumption, and it is assumed that these customers will be allowed direct access to the wholesale market. The remaining load, less than 200 mw, will be divided among five regional electricity distributors.

4.3.1. Are Any Of The Regional Electricity Distributors Large Enough To Be Effective Wholesale Market Participants?

If the current amount of retail load in Namibia (about 250 mw) were equally divided among five distributors, none of them would be large enough to be likely to be successful operators in a wholesale market structure. If the Windhoek-area load, which comprises a very significant percentage of the total, were served by one distributor, that one distributor would approach a size where it could function efficiently in a wholesale market, but the other four could not.

4.3.2. Providing For Energy Efficiency Funding

It is well-recognized that utility funding of energy efficiency programs can lead to lower total energy costs, mitigated environmental impacts, improved reliability, better customer satisfaction with the utility system, and better matching of new resources to demand growth.

Currently, NamPower does not have an energy efficiency funding mechanism, nor does it operate energy efficiency programs. The benefits of such programs are not being achieved in Namibia, and the lack of efficiency is evident in the most cursory audit of residential and commercial energy usage.

Implementation of a system benefit charge (SBC), either at the national grid level, or for each of the regional electricity distributors; and dedication of those funds to energy-related public purposes, including energy efficiency, should be a priority for Namibia

The five regional electricity distributors would appear to be well suited administer energy efficiency funding, since each will be a regulated and exclusive provider in their regions. A public process should examine the level and specific applications of this SBC for renewable energy, for low-income energy assistance, for universal service expansion, and for energy efficiency programs. In general, an SBC in the 2% to 5% range is adequate to support a wide range of activities, but neither the need nor the cost for Namibia has been explored.

4.3.3. Use of an Uplift Fee / Transmission Level Funding Source

One issue that should be examined is whether the SBC should be imposed at the local distribution level, or at the transmission level. The difference is that NamPower serves, and is expected to continue to serve some large industrial sites directly from the transmission system. Applying the SBC at the transmission level would provide additional funding to the program, would better match payments with benefits (since all customers, including direct access customers, benefit from the reliability and price benefits of efficiency investments), and would logically result in the availability of SBC program funds for industrial energy efficiency. Most studies of efficiency availability suggest that the most cost-effective opportunities are in the industrial sector, and that industrial customers will not pursue all cost-effective options without programmatic support.

4.3.4. Creation Of A Separate Demand-Side Entity To Work Across Boundaries

Several regulators have opted for the creation of separate demand-side organizations to implement energy efficiency programs across the boundaries of individual distribution utilities. Examples exist in California, Vermont, New York, the U.K., and in New Zealand.

The advantage of an "Energy Efficiency Utility" as these are commonly called is that it has only a single mission – efficiency – and is unlikely to be discouraged by utility industry tendencies to prefer growth in sales.

The Regulatory Assistance Project did an extensive review of alternatives for supplying ratepayer-funded energy efficiency in the USA. This study examined several states where efficiency programs were managed by non-utility program managers, and many where utilities managed the programs.. It concluded that the key factor was the attitude of the utility; where they were not unambiguously supportive of efficiency implementation, it was better to have a non-utility entity provide the service. Because NamPower is not particularly supportive of end-use efficiency programs, this study would seem to suggest that a non-utility program administrator should be considered for Namibia.

In Namibia, with a very small national electricity demand, newly created regional electricity distributors, (most likely, without energy efficiency expertise), and some very attractive efficiency opportunities, there would be a definite benefit to centralizing energy efficiency activities in a single organization. The logical question would be whether that should be NamPower or a separate energy efficiency utility. The ECB will havle an important role in defining the form, function, and funding mechanisms for energy efficiency programs in Namibia. This should follow close on the adoption and implementation of an IRP requirement for the single-buyer, and not wait until the wholesale market evolves.

Given the current attitude of NamPower toward utility-supplied energy efficiency (it has no programs), it is probable that a separate entity would be a good choice for Namibia. This should be explored with stakeholders, and appropriate legislative and ministerial support should proceed.

4.4. Equal Transmission Access and Pricing

Transmission Pricing

There are a number of transmission pricing issues that will need to be addressed equitably in order to facilitate a viable multi-national wholesale market. Some of these apply within Namibia, and are within the authority of the ECB, and some will require international cooperation.

Equal transmission access, subject to the availability of technical capacity, is guaranteed in Namibia through section 28 of the Electricity Act of 2000. This is also a licence condition in the national transmitter's licence. The implementation details of this principle are currently being dealt with through the drafting of the Namibian Grid Code.

In the RSA legislation, equal transmission access is not dealt with specifically. Equal transmission access is however dealt with in the recently established Grid Code.

In the SAPP agreements all operating members are required to make their transmission networks available for wheeling.

4.4.1. Namibia

The ECB has accepted the principle of cost-reflectivity in electricity prices including transmission. Thus the national transmitter is entitled to recover energy purchases, operating cost, depreciation, corporate overheads, finance charges, taxes and allowed profit component (RoA) from transmission customers.

It is envisaged that the cost of the Tx backbone will in future be split between generators and loads to provide incentives to both producers and consumers to minimize Tx backbone costs.

Currently the "postage stamp" approach to transmission pricing applies, i.e. customers pay the same rates regardless of their physical location in the network. Customer-specific costs (connection & extension charges) apply for customers with dedicated infrastructure.

Special pricing agreements are allowed to promote investment in Namibia. The principles for special pricing agreements are contained in the soon-to-be promulgated Economic Regulations.

Namibia currently employs no pricing system for congestion management, as transmission capacity is exceeds current requirements and the network is predominantly radial.

4.4.2. South Africa

The South African transmission pricing system has been the same as Namibia but this is to change soon by the introduction of the wholesale electricity pricing system (WEPS) in the RSA.

Essentially the WEPS introduces an energy loss component and a reliability charge component, both of which vary according to the distance from the major generation centers. For this purpose the country is divided into 4 zones. Details of the WEPS are contained in Annex 4.3.A.

The WEPS is a fairer system than the postage stamp system because locational signals are sent to existing and prospective transmission customers. It is believed that the WEPS is introduced to minimize transmission price shocks to customers and that ultimately the RSA will move to a nodal system (energy loss & reliability charge component determined locationally through scientific methods) of transmission pricing.

Various alternatives for congestion management are currently being considered as detailed in Annex 4.3.B.

4.4.3. The Southern Africa Power Pool (SAPP)

Currently only national utilities are allowed to participate in the SAPP and most of the power is traded through bilateral agreements (a small percentage is traded through the short-term energy market or STEM). Therefore transmission pricing within countries are dealt with by the respective utilities. What is more of relevance for this paper is the principles applied in determining the wheeling charges.

Wheeling charges in the SAPP have a network charge component (fixed for each wheeling situation), a variable component determined by the amount of wheeled energy multiplied by the distance of wheeling and an energy loss component. The energy loss component is determined scientifically by utilizing an engineering software model of the Southern African grid. The detail of how the energy loss component is determined is contained in Annex 4.3.C.

4.4.4. Transmission Issue Summary

A wholesale market within Namibia is unrealistic and impractical. The logical option for Namibia is to move towards participation in a Regional Wholesale Market that will probably evolve from the merging of the South African Multi-Market Model with the Southern African Power Pool.

Non-discriminatory access to transmission networks is a principle that will be applied in the movement towards a Regional Wholesale Market.

Transmission pricing in a Regional Wholesale Market will probably be initially based on the zonal method developing into the nodal method in the medium to long term. It is therefore advisable for Namibia to follow suit.

4.5. Integrated Resource Planning Requirements

In the Single Buyer chapter of this report, we discussed at length the Integrated Resource Planning (IRP) mechanism appropriate for a single buyer market structure. Here we discuss how that would differ for a wholesale market structure.

First, the key elements of an IRP are unchanged. The basic functions of a demand forecast, evaluation of supply-side and demand-side resources, integration analysis, risk analysis, funding mechanisms, and all other elements of the IRP remain the same.

Second, a question develops quickly as to whether each of the regional electricity distributors should prepare an individual IRP, or whether a single national IRP is more appropriate. For the reasons discussed in the Single Buyer section, a single national IRP is more likely to meet the needs of Namibia at reasonable cost. The total electrical load of Namibia (and the population served) is at the low end of the range of size for which IRPs are most often prepared.

The clear difference between the wholesale market IRP and the single buyer IRP processes is that the individual regional electricity distributors will make their own resource acquisition decisions in the wholesale market model. This is not unlike the system in the Pacific Northwest of the United States, where the Northwest Power Planning Council prepares a regional IRP, and more than 100 individual distribution utilities (some of which own generation as well) make their own resource acquisition decisions. Those decisions are *informed by*, but not necessarily *controlled by* the regional IRP.

Examples of when a local resource decision might be appropriate, but inconsistent, could include the following:

- The national IRP failed to consider local conditions;
- Evolving technology made a different choice economic

- Local economic development opportunities, such as cogeneration at an industrial site, created values for locally-developed resources that were not considered in the national IRP

- Avoidance of lost opportunities: if not developed at a particular time, a resource might never be developable.

It would make sense for the regulator to put in place a mechanism by which a regional electricity distributor that makes a resource acquisition decision that is inconsistent with the national IRP to explain their actions. Alternatively, the regulator could require each distributor serving load to accept the national IRP as a platform, and conduct a local planning process to consider "portfolio modifications" that could be appropriate at the regional level. Waiting until a tariff proceeding, where the inconsistent acquisition might be disallowed, is probably too late for this type of review. A periodic review of compliance with the IRP will make it possible to ensure that the regional electricity distributor does not deviate too far from the IRP.

4.6. Portfolio Risk Management Capability

Under the wholesale market model, the portfolio management responsibility shifts from the Single Buyer to the individual regional electricity distributors. The regulator needs to promulgate standards for portfolio management designed to limit both cost volatility and supply risk, and enforce these standards effectively.

In 1997, California elected to abandon portfolio management, in favor of retail access, with a default supply tied to the spot market. The most important lesson of the California energy crisis is that the responsibility to develop and maintain a diverse portfolio of electricity supplies must be assumed by some entity, or else chaos can ensue during a period of short-term market instability.

The portfolio of the regional electricity distributors could consist of any mixture of owned resources, contracted resources, long-term supply arrangements, short-term supply arrangements, spot market resources, and energy efficiency resources. Balancing this portfolio to achieve a low-cost, low-risk, high-reliability portfolio is a challenging task, and one that many utilities have not achieved very well.

Demonstration of a well-planned energy portfolio risk management capability should be a strict precondition for any distribution utility or industrial customer to leave the system for direct participation in the wholesale power market.

A brief discussion of the types of resources, the advantages and disadvantages of each, and the role that each should plan in a balanced portfolio follows. A much more intensive discussion of these can be found in the reference documents on portfolio management, identified in the "Is a Wholesale Market Practical for Namibia" chapter.

4.6.1. Owned Resources

Historically, electric utilities have directly owned many of their generating resources. These include both baseload resources and peaking resources.

Examples of these would include hydroelectric resources like Ruacana, coal units like the Windhoek generating station, and peaking units like the Walvis Bay diesel unit.

Some of the principal advantages of utility ownership are:

- Utilities historically had lower borrowing costs than other power producers due to their stable business model and revenues;

- The utility is assured of adequate maintenance of a facility, and can plan and coordinate maintenance of multiple facilities to achieve system reliability;

- The benefits of the resource accrue to the utility and its customers for the entire operational life of the resource, not just the contract term.

Some of the principal disadvantages of utility-owned resources are:

- When utility-owned resources fail, customers typically pay both the cost of the owned resources and the cost of replacement power.

- The utility, particularly a smaller utility, may not have the expertise to own and operate a diverse portfolio of resources

- It may be impossible for a smaller utility to own a low-cost, diversified, reliable mix of resources.

4.6.2. Contracted Resources

Over the past twenty years, the global electricity industry has moved toward non-utility ownership of generation resources. The emergency of independent power producers that specialize in building, owning, and operating generating resources and available financing have fueled this transition. Contracted resources take a wide variety of forms, discussed in much greater detail in the Purchased Power Agreements section of this Report. Here we will briefly summarize the types of contracts that are typically used.

4.6.2.1. Long-term Contract Resources

A long-term contract is normally more than five years in duration, and will often be for a period estimated to equal the physical or economic life of a power plant. Twenty years is not atypical.

In a long-term arrangement, the buyer typically commits to a "two-part" payment. They pay the fixed costs of the power plant in well-defined monthly or annual payments, and has the right to dispatch the power plant as needed, and pay for the variable costs when this occurs. For hydro projects, the dispatch flexibility is normally limited by available water and environmental constraints.

Long-term contracts can be for any type of power plant. The usual purpose of a long-term contract is to provide the developer the market certainty needed to attract capital at a reasonable cost.

The utility benefits if the independent power producer has expertise or the ability to achieve efficiencies that the utility cannot achieve, or has access to capital at lower costs than the utility.

One factor discussed in the PPA chapter, that merits repeating here, is that the financial community views a long-term contract as a form of "debt" of the utility, and it will be reflected in the utility's bond rating and cost of capital.

4.6.2.2. Short-term Contract Resources

Short-term contracts are entered into for a period of one to five years. Since the contract provides only partial assurance that the resource developer will be able to recover their costs, the developer must have more financial strength before they can borrow funds to build a project backed only by short-term contracts. Following the upheavals in many markets, it has become increasingly difficult for developers to attract capital to build power plants in the absence of long-term contracts with creditworthy buyers covering a very substantial fraction of their total output.

A very common form of short-term contract is when one utility builds a resource that is larger than their immediate needs, and sells a portion of the output to another buyer (typically a nearby utility) for a limited number of years. The expectation is that the resource will eventually be needed, and absorbed into the utility's system.

Short-term contracts can be either two-part (fixed plus variable), or else for specific hourly amounts of power at specified energy prices.

4.6.2.3. "System Sales" vs. Resource-Specific Contracts

Some contracts are for what are known as "system sales" where the seller operates a number of power plants, and commits to delivering power in the amounts specified by the contract, without identifying a particular power plant. If the lowest-cost unit is not available, they provide that power from other resources. This type of contract, particularly when executed with a seller operating many different resources (especially resources not exposed to the same fuel cost escalation risks), provides a more reliable and predictable power supply. Even here, however, the buyer must accept some risk that the seller will experience financial, institutional, or managerial problems that make the supply contract less than certain over a multi-year period.

Other contracts are for specific resources. In these situations, the contract normally specifies who is responsible for providing power during periods when that specific resource is not operating. Sometimes the contract provides that replacement power is the seller's responsibility at all times. Other contracts provide that a limited number of hours of "forced outage" are assumed, and are the buyer's responsibility to plan for, with the obligation shifting to the seller only if the outage exceeds the contractually specified length. Resource specific contracts can often leave the utility with a much greater risk of either high replacement power supply costs or lower reliability, compared with system sale contracts executed with large, multi-resource sellers.

4.6.3. Spot Market Resources

A essential element of a viable wholesale market is the existence of an adequate level of spot market resources to meet unexpected levels of demand, and to replace the output of resources that fail unexpectedly.

Spot market power prices are highly volatile. During most hours of the year, spot market prices are typically much lower than long-term contract prices, because idle power plants compete for sales at prices that are bid down to the variable operating costs. During a much smaller number of hours, spot market prices typically soar, when capacity is scarce, loads are high, and sellers are few and far between.

As discussed in the section of this report responding to specific questions from the ECB staff, the spot market needs to be large enough to cover anticipated contingencies, but should not dominate the portfolio, or the overall cost of power will be too volatile.

4.6.4. Demand-Response Resources

It is increasingly recognized that unusual load/resource balance conditions should be addressed with both spot-market purchases of power and with arrangements with consumers to reduce their power demand under high-cost conditions. The latter type of arrangement is known as "demand-response."

Demand-response resources can be acquired in several different ways. Historically, large industrial customers were offered "interruptible" rates in exchange for the ability of the utility to curtail power deliveries under specified circumstances. Demand-response can also be arranged with "buy-back" tariffs, in which the customer pays a normal tariff rate for a reliable power supply, and the utility periodically offers to "buy back" some or all of the "normal" level of usage for a specified price, providing a savings to the utility compared with buying an equivalent amount of power in the sport market to cover the load in question. Finally, tariffs can be established with an explicit provision for tariffs to rise to a spot-market level under extreme conditions, leaving the customer to choose between paying the high price or reducing their usage.

All of these approaches are valuable, and should be examined in the context of assembling a low-cost, high-reliability energy supply portfolio. A recent comprehensive report on these approaches, developed by the New England Demand Response Initiative, is contained in the Reference Material for this chapter.

4.6.5. Energy Efficiency Resources and Investment

A low-cost, low-risk energy portfolio also needs to include all cost-effective energy efficiency resources. The proper way to evaluate efficiency resources is through the IRP process, discussed at length elsewhere.

Efficiency resources are unique in a supply portfolio, generally more valuable than supply-side resources, for the following reasons:

- By reducing demand at the consumption end of the system, they avoid transmission and distribution costs and losses, not just generation costs;
- A utility's reserve capacity requirement is a function of its load, and therefore efficiency resources, by reducing the load, also reduce the reserve requirement and associated costs.;
- Many types of efficiency resources (energy codes, appliance efficiency standards, motor efficiency standards) apply to new construction, and by reducing the load increment per new customer or new facility, reduce the uncertainty associated with system growth.
- Efficiency resources come in very small increments, and can be built as needed to more precisely to coincide with system needs than "lumpier" supply-side additions.
- Efficiency resources have much shorter lead times, and can be built as needed, reducing the risk of over-building or under-building.

The regulator of utilities operating in a wholesale market model should adopt very specific rules for incorporation of efficiency resources into portfolio evaluation and portfolio management. The review of the IRP should ensure that all of the benefits of efficiency are accounted for, and that all cost-effective efficiency measures are identified, measured, and incorporated. Any resource acquisition process should provide for priority identification and acquisition of efficiency measures. And any prudence evaluation of an energy supply portfolio (whether done in a tariff proceeding or in a separate process) should include examination of whether all cost-effective efficiency measures have been secured.

4.7. Licensing of Sellers to Ensure Financial Strength (i.e. Enron experience)

Much of the discussion in this Report has focused on the regulator's relationship with the utility providing retail service to consumers. The regulator also needs to have a relationship with sellers of power in the wholesale market model.

Because competition is assumed to be the principal determinant of prices in the wholesale model, the regulator is not expected to regulate the price charged by sellers. It is, however, expected to assure that markets are vibrant, that competition is fair, and that sellers are capable of delivering under their obligations. The first of these have been addressed in the section on Market Rules. This discussion addresses only the licensing requirements for sellers – the relationship of the regulator to individual sellers in the market.

The purpose of licensing sellers is to ensure that they have the technical and financial capability to deliver what they promise. Absent this more fundamental form of regulation, there can be no confidence that the overall goal of the electricity industry – to provide safe, reliable service at the lowest possible costs – can be met.

Ideally the licensing of power sellers will be done on a power pool basis, with common requirements applied throughout SAPP. This is because each seller wants access, and for the goals of competition to be met, needs access to all buyers on the system.

The first set of requirements should be technical: can the seller deliver power into the grid at a location where it can be accommodated, at a voltage and frequency consistent with grid requirements. Because the grid is so interdependent, these standards cannot be flexed for any suppliers.

The second set of requirements should be financial: does the seller have the financial resources to be able to deliver their product at contractual prices for the term of the contract. These standards are more flexible than the technical standards; a seller seeking only to offer power in the short-term spot market does not need as much financial stamina as one offering a fixed price product for a twenty-year term.

The financial requirements for longer-term contract sellers need to be tailored to the types of resources, the term of agreements, and the pricing terms of a contract. The more risk that the seller is responsible for, the more certain must be their financial condition.

This is not a trivial bit of analysis. Even financially strong market participants can be rendered vulnerable by market changes. Prior to the California energy crisis, Enron, Mirant, Reliant, Dynegy, NRG, and Williams were all thought to be very strong sellers, with adequate resources to deliver on their contractual obligations. Today, Enron, Mirant, and NRG are in bankruptcy proceedings, and Dynegy and Reliant are considered very weak.

The financial requirements for seller licensing need to consider all applicable factors, taking into account the types of transactions that the sellers seek to engage in.

Some sellers may want to be "broad" participants in the wholesale market, entitled to buy and sell power supplies, options, futures, and other derivatives on an unlimited basis. These need to be subject to very strict financial qualifications. As discussed in the Market Rules chapter, we recommend that these participants be required to post, in real-time, every transaction they make in the wholesale market, and be required to post, at all times, both buy and sell prices for specific standardized power products. This is necessary to ensure that the market remains vibrant, and that all market participants have access to adequate information upon which to base acquisition decisions.

Other sellers may simply want to sell the output of facilities that they own, or to engage in spot market transactions to balance the output of resources they control (by ownership or contract) with the loads they need to serve (retail or industrial). Sellers not making long-term commitments in the market to regional distribution companies need not have anywhere near the depth of financial capabilities that a seller of a long-term contract needs.

4.8. Obligations to serve [Drafting of this section is being led by ECB]

4.8.1. Who is the default supplier to distributors?

4.8.2. What happens in case of a national shortage of power?

4.9. Issues for Large User Direct Market Participation Under Wholesale Design

Namibia anticipates that large industrial customers will be allowed to directly contract for power supplies in the wholesale market, in much the same manner that the regional electricity distributors are able to do. This is logical, since some of these industrial customers are as large (or larger) than the regional distributors, and their power supply needs are more predictable, making them attractive customers to wholesale sellers. This is not uncommon; in regions of the world where retail access has been implemented, it is primarily the large customers that have taken advantage of the opportunity, and in many areas, only the large customers have been permitted to directly contract for power.

In order to protect the interests of Namibians that are not large industrial customers, however, certain requirements must be imposed on these type of power users. These requirements include specific requirements on their departure from and re-entry to access to general power supplies, their role in assuring reliability of the grid as a whole, and their impact on prices paid by other consumers. We briefly discuss each of these issues below.

4.9.1. Contribution to Reliability Services (reserves, transmission redundancy, etc).

Industrial customers that contract directly for power supplies should have the same obligation to assure the reliability of power supplies as the regional electricity distributors. If the customers are entitled to firm transmission service, they must contribute financially (through transmission prices set by the regulator) to transmission system capacity costs, so that the system is able to absorb the design contingencies.

Depending on whether sellers or buyers are required to secure adequate generation capacity reserves, either the industrial customers or the vendors selling to them must be required to maintain adequate reserves. All or a portion of the reserves can be arranged in the form of interruptible service to the customer in question, or demand response resources supplied by others on a contractual basis, but the manner of interruption must be contractually secure and automatic (through the use of under-frequency relays, for example). This ensures that the failure of the power supply contracted for by an industrial customer does not result in outages to other customers.

4.9.2. Stranded Cost Obligations and Re-entry Rules

An industrial customer leaving the utility system to engage in wholesale market purchases potentially leaves the electricity distributor holding a power supply that was contracted for under the assumption that the industrial customer's load would continue to be a part of its market. If the short-run cost (ownership or contract costs) of this power exceeds the short-run market value (spot market or short-term contract market), then the customer has caused a "stranded cost" to be imposed on the utility. The customer should be required to continue to pay the distribution utility for the amount of stranded costs being imposed on the utility by their departure. This typically takes the form of a specific dollar charge for 1 – 5 years after the customer leaves the utility's system.

Similarly, if an industrial customer finds that participating in the wholesale market is not working for them, they may want to return to the system. Since the utility has not been planning to meet their demand, it does not have a power supply portfolio optimized to meet the combined demand of its other customers plus the industrial facility. If, in the short-run, the cost of augmenting its power supply exceeds the amount reflected in its retail prices, the industrial customer should be required to pay a re-entry fee to the utility to return to the system. This is most often accomplished by placing the customer on a higher, market-based tariff for a period of 1 – 5 years, until the utility can again optimize its power supply portfolio to accommodate the industrial customer without adverse impacts on others.

4.9.3. Synergies between big customers and small customers.

There are a number of synergies associated with having all power consumers served by a single power supplier and having a single portfolio manager acquiring power for a diverse group of retail power consumers. First, there are economies of scale in fulfilling the portfolio management function. Second, there are minimum market transaction sizes that are more easily accommodated by a smaller number of larger market participants. Third, there are seasonal, diurnal, and other load diversities between different types of customers[3] that make it economical to maintain a single power supplier.

When industrial customers leave the utility system, some of these synergies may be lost. If the customers fully pay for their replacement power supplies, fully address the reliability issues discussed above, and the wholesale market is vibrant and robust enough to accommodate multiple customers with different usage patterns without significant transaction costs or other "friction" these impacts may be negligible.

It is up to the regulator to determine if there are adverse impacts on remaining customers that a departing industrial customer should be held responsible for. An example of this might be a situation where a distribution utility serves the sum of industrial load plus

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[3] In many areas, electric distribution system grew up around industrial customers, which operated generating facilities to run their own facilities by day, and sold power to their employees for home use at night.

smaller retail customers, and is able to be an efficient and effective participant in the wholesale market. With a mix of high load-factor customers and lower load-factor customers adding up to an attractive demand, it is able to secure favorable treatment in the market. With the loss of industrial load, it might lose that ability. The regulator would need to balance this issue, determining whether the industrial customer brings such benefit to the distribution utility that it should offer a lower price, or whether the industrial customer's departure imposes costs on remaining customers, which should be charged to the departing customer.

4.9.4. Standby Service for Self-Generators

Some industrial customers depart the utility system to self-generate some or all of their power supplies. These customers than need to buy "standby" service from the utility or from the wholesale market. There are many ways to price such service that are fair to both the utility and the customer, avoid imposition of costs on other customers, and encourage the diversified and distributed energy resources that self-generation represents. Requiring a standby customer to pay the same annual level of contribution toward fixed capacity costs as other full-service customers is not fair, and the regulator needs to ensure that self-generators do not overpay for their standby service.

A "fair" standby rate would charge industrial customers that use power only a limited number of hours per year from the utility a much lower fixed cost contribution than full-service customers would pay. In order to remain connected to the system, they would need to bear, as fixed charges, the costs of extending and maintaining the grid connection, but would make only small contributions toward the fixed cost of generating capacity. This assumes that the customer has provided, either through a fair contribution, or interruptible obligation, its fair share of total system reliability requirements. Such requirements are needed to ensure that a customer does not impose high burdens on the system at a time of peak or shortage, while contributing less than other customers for maintenance of reserves.

An option of providing interruptible or "best-efforts" standby service should be considered. If the customer schedules their maintenance in coordination with the utility, there is a low probability that it will impose a standby demand at a time when the utility system is also facing peak power demands, and the standby service can be provided at little incremental cost to the utility. Under this option, if the self-generation equipment failed at a time of utility peak demand, the customer would not receive standby service, and would have to curtail operations.

However, if the self-generator elects standby service but turns out to be dependent on the utility more than a specified number of hours per year, they should pay a premium above the rate paid by a full-service customer. This is appropriate because they are BOTH imposing a demand comparable to a full-service customer AND doing so in a manner that cannot be accommodated in the IRP process as predictably as a full-service customer. This is best accomplished by imposing a discounted demand (fixed) charge to the standby customer, and a premium energy (variable) charge. If they actually take standby service for too many hours per year, their total cost of power would exceed that paid by a full-service customer.

An example of a constructive standby rate, from Southern California Edison Company, is included in the reference materials for this chapter.

4.9.5. Should industrial customers participate directly in SAPP, or only through scheduling entities?

As a general rule, only scheduling entities (those that actually control and/or direct the dispatch of power plants) should be direct market participants. An industrial customer desiring direct market access, but unable to perform as a scheduling entity, would normally contract for service through a broker or marketer that can perform the scheduling function.

This is not normally an obstacle to industrial customer participation in competitive wholesale markets, as the market will evolve so that scheduling entities engage in power transactions with such customers.

It should be noted that it is now technically possible to electronically "relocate" an industrial customer from one control area to another. This is done with telemetry to the operator of the control area to which the customer is to be associated. The customer load is transmitted in real-time to the control area operator, which then schedules power to meet that load along with all other load in the (discontinuous) control area. All that is needed is a firm transmission path between the resources controlled by the control area operator and the customer site. An example of this was done across national boundaries by British Columbia Hydro, adding a U.S. aluminum smelter (that was buying surplus power from BC Hydro) to its control area in 1996.

4.9.6. System Benefit Charges for Large Users on Direct Access

The issue of whether to collect an SBC from large users choosing direct wholesale market access is a matter for policy discussion within Namibia. As discussed in the section of this report on the single-buyer / IRP issues, the principal advantage of doing so is to achieve cost-effective savings that will not otherwise be obtained, and to ensure that all customers who benefit from widespread efficiency investments pay a fair share of their costs.

In many jurisdictions, large-use customers are allowed to "self-direct" the majority of their SBC payments into efficiency improvements at their own facilities. A portion is retained as a contribution to the cost of research and development, market transformation, and other efficiency programs that are best operated in a central manner.

4.9.7. Physical Bypass: What If an Industrial Customer On The Distribution System Of A Regional Electricity Distributor Wants To Access the Market Through Physical Connection to the Transmission Grid?

This is a stranded cost issue relating to the distribution network, and should be handled in the same manner as stranded cost issues related to generation discussed above. If the bypass will result in higher charges to remaining customers, because the system was built to handle a larger load, the industrial customer should expect to pay an exit fee or stranded cost surcharge. If there will be no impact or a beneficial impact on remaining customers, no surcharge is indicated.

Physical bypass of the distribution system can be economically justified for large loads that are located close to transmission facilities. This is particularly true if the Regional Electricity Distributor's facilities are nearing capacity, and a capacity upgrade is planned. It may be simpler, cheaper, and improve reliability to directly connect a large load to the transmission system than to upgrade the sub-transmission and distribution network. One reason for this is that the direct bypass allows a high-voltage connection to extend for the maximum distance, reducing line losses compared with providing distribution level service.

4.9.8. How To Price Wholesale Service

The simple answer to this is that the electricity regulator normally does NOT price wholesale service: the market performs this function.

As discussed in the Market Rules chapter, all large participants in the wholesale market should be required to post bid and ask prices for specific standardized market products, much as a market-maker or specialist do in the securities markets. This will create a well-defined and transparent market for wholesale services that will give all participants access to adequate information upon which to base acquisition decisions. Customers needed or wanting more specialized products will be able to use the standard market products as a guide to price.

The electricity regulator will be setting the prices for transmission and distribution service to customers acquiring their own power in the market. The tariff design issues for this service are beyond the scope of this report.

4.10. What Expertise Is Needed For Market Participants to be Successful?

The monopoly utility or single-buyer performs a large number of functions in securing and managing power supplies for industrial consumers. In the transition to a wholesale market model, each of these functions needs to be assumed by (at least) one of the market participants, or the system will be at risk of unanticipated pricing volatility, unacceptable reliability risk, and/or adverse impacts on remaining retail consumers.

It would be possible to approach this from a function perspective: who is responsible for power acquisition, scheduling, reserves, efficiency programs, and so forth. Instead it is discussed here from an institutional perspective: what functions do each of the participants have responsibility for.

4.10.1. Government / Ministry

The principal role of the government and Ministry should remain the formulation of elements of national policy. This would include whether to permit market access for individual consumers, consideration of resource development priorities, involvement in the development of the national IRP, and enforcement of applicable land use, environmental, and other functions that have not been delegated to the Regulator.

4.10.2. Regulator

The Regulator is the hands-on representative of the government in implementing the policies that are set at the parliamentary and ministerial levels. This would include determining whether, when, and how the Single-Buyer framework should give way to a wholesale market model, and which regional electricity distributors have the capability to be effective participants in the wholesale market. It would determine which industrial customers would be eligible for market access, and the stranded cost obligations they must bear. The Regulator sets the market rules for wholesale sellers into the market, and enforces violations of those rules. The Regulator will determine and approve both transmission and distribution tariffs applicable to industrial customers that acquire their power supply in the wholesale market.

Additionally, the Regulator retains all of the responsibility for regulating the retail prices charged by the regional electricity distributors for electricity supply and distribution service. It will determine if the acquisitions of resources are prudent and recoverable from customers. It will set the service quality standards for the regional electricity distributors, examine their line-extension policies, their construction budgets, and their operating policies. These roles are no different that the charge to the ECB under the current structure.

4.10.3. Wholesale Supplier

Perhaps the most significant changes that may occur in a wholesale market model will be the evolution of new types of wholesale suppliers. Eskom currently dominates Southern Africa's power market and is the wholesale supplier of most power that is not owned by the utility system in Namibia. This must change if a viable wholesale market is to evolve. As discussed above, unless and until there are numerous wholesale suppliers, none with a dominant market share, a competitive wholesale market cannot be assumed to exist.

There will likely be at least four different kinds of wholesale suppliers in a future competitive market:

- Entities that own (or control by long-term contract) a portfolio of generating resources that can be dispatched to meet power demands. For convenience, these will be called "full-market participants."

- Entities that own (or control by long-term contract) one or a small number of generating resources, that have limited ability to shape their output to meet power demands. For convenience, these will be called "single-resource owners."

- Utilities that hold portfolios of resources (by ownership and by contract) to meet their demands, but have surplus power available at least some hours of the year that they desire to market.

- Demand-side suppliers of relief capacity and energy efficiency, that seek to market power consumption reductions in competition with supply-side vendors marketing kilowatts and kilowatt-hours.

Each of these types of wholesale supplies requires different types of information and skills in order to be successful participants in a future competitive wholesale market.

Most important will be the full market participants. These will typically be the primary entities in the marketplace, and the only ones normally selling ancillary services to the distribution utilities. They will need to have the same type of expertise that control area managers have today – the ability to shape and dispatch their resources to meet a broad range of potential demands and deal with variable reliability of resources.

The single-resource vendors will typically be selling either to full market participants or to utilities with a broader portfolio of resources. There may be opportunities for them to team with demand-side marketers to provide a power supply that meets the reliability requirements set by market rules. In either case, their knowledge needs are limited to understanding their own resources, and understanding the ancillary services that are needed for these resources to meet customer demands.

The utilities, in a post-single-buyer world, will need to have sophisticated portfolio management skills. Typically, these will focus on the acquisition of a diverse portfolio of supplies to meet an unpredictable load. These same skills will generally be applicable to marketing any surplus energy or capacity that they hold at any point in time.

The demand-side marketers are in a very different niche, but need to fully understand how all parts of the power supply network operate in order to be profitable and successful. A well-designed IRP process will identify potentially advantageous roles for these marketers. Market rules, and reliability standards and rules, should also be designed to support a vibrant market for competitive and cost-effective demand-response resources.

4.10.4. Regional Electricity Distributors

Perhaps the most important evolution that needs to occur for a successful wholesale market model to evolve is the development of technical expertise in resource acquisition and portfolio management on the part of the regional electricity distributors.

Throughout the world, there are examples of successful and unsuccessful portfolio management by utilities. The tools and skills needed for success are considerable, are not intuitive, and are very different from the tools and skills needed to be a reliable and cost-effective provider of utility distribution services.

First and foremost, the buyers of wholesale power must understand the intricate inter-relationships between power producers, marketers, transmission providers, electricity distributors, and energy consumers. This must include an understanding of the load profiles of different types of consumers, the end-uses driving their loads, and the means by which loads can be reduced or modified in order to improve reliability and lower total power system costs.

Second, the procurement function requires a thorough understanding of portfolio management theory, and training in the use of portfolio management tools. Simple power contracts are easier to understand than derivatives, but tools such as hedges, futures, options, and strips are all an important part of the power portfolio development process. Both supply-side and demand-side resource options and risk-reduction tools need to be understood and made available to portfolio managers.

Third the buyers must have enough "depth" of personnel that no individual involved in the power procurement function is critical to the success of the operation. The principal reason for this is that the market for this type of expertise is highly competitive, and experience suggests that these experts tend to be mobile in their employment. Obviously, having a group of experts also provides protection against contingencies such as injury, illness, or death of the employees.

An example of the importance of the role of portfolio management can be seen in the performance of the larger utilities in the Western United States at the time of and in the wake of the California energy crisis. The list below simply breaks down some of the major regional utilities (minimum 300 mw peak demand) between those that suffered rate increases of more than 40%, and those that held increases to less than 20%.

<20% Increases	20% - 40% Increases	>40% Increases
Los Angeles Department of Water and Power	City of Burbank, California	Southern California Edison
Sacramento Municipal Utility District	City of Pasadena, California	Pacific Gas and Electric Company
Pacific Power and Light Company	City of Glendale, California	San Diego Gas and Electric Company
Puget Sound Energy	City of Anaheim, California	Portland General Electric
Chelan Public Utility District	Bonneville Power Administration (and more than 80 "requirements" public utilities buying through BPA)	Avista Utilities
Grant Public Utility District	Idaho Power	Snohomish Public Utility District
Eugene Water and Electric Board		City of Seattle

When looking at this list, some very important common characteristics become evident. The utilities that held increases in consumer prices to 20% or less almost all had secured portfolios of medium to long-term power supplies adequate to meet their needs, with generally limited exposure to volatile natural gas prices. Those that suffered the highest rate increases generally had not made long-term provision for at least a significant portion of their power supply, and were forced to make substantial acquisitions in a difficult market. Those in the middle generally had made provision for the majority of their power needs from a capacity perspective, but were exposed to spot market prices for either a substantial portion of their power needs, for a substantial portion of their fuel requirements, or both.

Portfolio management is a difficult, dynamic, and confusing area of expertise. The Regulator should be very certain that the needed skills are in place before shifting the responsibility for procurement from the Single Buyer to the individual regional electricity distributors.

4.10.5. Industrial customers

Much of the electric industry restructuring that has occurred around the world has been driven by industrial customers seeking access to lower priced power supplies that they presumed would be available on wholesale markets. These customers purchase most or all of their other inputs to their processes from competitive suppliers, and generally believe that electricity should be no different.

In general, industrial customers can develop the expertise they need, or can purchase multi-year contracts for power from suppliers that have the ability to provide the full menu of services that industrial customers need.

Caution should be applied to industrial customers that choose to meet their needs in the spot market. There are several examples of industrial customers that relied on short-term and spot-market agreements for their needs, that were then overcome by price volatility. Some of these cases have been devastating to the industries, and others have been huge public policy challenges for regulators.

Nine aluminum smelters with a total demand of 3,000 mw, located in the Western United States, have curtailed operations since 1999, most of them permanently, due to power prices that exceeded their ability to pay. The one that continues operating is applying significant political pressure to secure a multi-year below-cost power contract.

A group of industrial customers of Puget Sound Energy, that secured access to market-based pricing in 1996, came back to the regulator in late 2000, asking for relief from their decision. The smaller customers were allowed to return to the utility and receive power from its much more stable portfolio of resources, while the largest were released to the wholesale market. Some of the larger industries have ceased operation permanently.

Several of the industrial customers that chose to buy spot market power became financially insolvent, and used the bankruptcy process to avoid the commitments they had made for transmission and other services. This left several of the providers with stranded costs, which have adversely affected remaining customers.

Because industrial customers can be the foundation of a local, regional, or national economy, the regulator should be concerned about any decisions that will leave those customers exposed to unlimited market price volatility. Establishing a portfolio management standard for industrial customers choosing to access the wholesale market directly could address this. The various stakeholders may have suggestions as to the best way to assure these customers the benefits (if any) of wholesale market access, while simultaneously assuring that their operations will not be at risk if market prices become volatile.

4.11. Reference Materials for Steps to A Wholesale Market Structure

Demand-Side Resources and Regional Power Markets: A Roadmap for FERC, Richard Cowart, The Regulatory Assistance Project (January 2002)

System Benefits Charge Case Studies, Ed Holt (August 1995)

Who Should Deliver Ratepayer Funded Energy Efficiency? A Survey and Discussion Paper for ACEEE Market Transformation Conference: Portfolio Management: The Post restructuring World, Cheryl Harrington, The Regulatory Assistance Project (April 15, 2003)

2002 Annual Report Eskom Holdings (2003)

Portfolio Management: Looking After the Interests of Ordinary Customers in an Electric Market That Isn't Working Very Well, Regulatory Assistance Project, 2003

Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers (Synapse Energy Economics, 2003 [Draft Not Available For Release Until 10/03]

Final Report, New England Demand Response Initiative (2003)

Standby Rate Proposal to California PUC, Southern California Edison (2003)

Dimensions of Demand Response: Capturing Customer-Based Resources in New England's Power Systems and Markets, Report and Recommendations of the New England Demand Response Initiative, New England Demand Response Initiative (July, 2003)

5. Market Rules, Market Monitoring

5.1. Context

This is a subchapter of a work in progress on the transition from a single-buyer electricity market model to a wholesale competition market model. This partial draft is being provided separately in order to maintain a gradual flow of work product for internal review from Nexant and its subcontractor, Regulatory Assistance Project. The total package is planned for completion by October 1, 2003. Comments on this partial draft are welcome, and will be addressed in the October 1 comprehensive draft if possible.

5.2. Introduction

A viable wholesale electric power market needs well-defined rules that facilitate competition, while ensuring that power supplies are reliable, that competition is fair, and that market manipulation is difficult, if not impossible.

The alternative to well-defined market rules is essentially chaos. The best example of how unregulated markets can fail to provide reliable, economic power supplies is the evolution of restructuring in New Zealand. A pioneer in restructuring without any form of economic regulation, the country has suffered massive increases in power cost, dramatic declines in reliability, and has recently decided to appoint an Electricity Commission to "*administer the operation and evolution of the market, principally covering electricity trading, and transmission pricing and investment.*"[4]

To achieve the goals of efficiency and reliability, rules are needed for many aspects of the wholesale electric market. These include:

- Financial Rules, which govern the minimum financial requirements for market participants; these are needed to ensure that buyers and sellers can perform under the agreements they negotiate.

- Technical Rules, which govern the transmission system and wholesale power supplies; these are needed to ensure that no individual market participant degrades the reliability of service for other market participants.

- Market Design Regulations, which address the pricing of power products; these are needed to ensure that power products are compatible and comparable by buyers and sellers, and to prevent market manipulation.

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[4] Cabinet Economic Development Committee, Proposal To Establish An Electricity Commission, New Zealand Minister of Energy, May 2003 [http://www.med.govt.nz/ers/electric/supply-security/cabinet/commission-proposal/]

- Market Monitoring Processes, which create high-quality market data for all participants, and allow regulators access to all market data. These are needed to ensure compliance with the financial, technical, and market design rules.

This review seeks to identify key market rules that would enable operation of an efficient, fair competitive wholesale power market for Namibia (and other interconnected countries in Southern Africa). It does not attempt to actually develop specific rules, as that is a very large role, appropriately undertaken by the Regional Electric Regulators Association (RERA) for all of Southern Africa.

5.3. The Importance of Market Rules

Economic theory holds that competition should produce an efficient allocation of resource if and only if the conditions of perfect competition are met. These preconditions are not traditional characteristics of the electric power industry. The specific conditions include[5]:

- Goods are identical, and are perfect substitutes;
- There are multiple buyers and sellers, none of which is large enough to "move" the market;
- There is only a single price for any good in the market, determined by supply and demand;
- There is no impediment to entry to or exit from the market;
- All buyers and sellers have perfect information about the market;
- Capital is fungible, and can be redirected to new production on short notice.

Electricity generally does not meet this set of conditions, for a variety of reasons. Most important are the facts that the capital employed in electric generating and transmission capacity cannot be deployed to other purposes, and cannot be replicated on short notice, and therefore both the fungibility of capital and the entry/exit constraints are not met. Further, unless market rules provide for transparency, the limited number of buyers and sellers, coupled with the fact that electricity is often sold on contracts of varying duration means that there is not a single price for the commodity, and buyers and sellers seldom have "perfect" information about the market. Finally, evidence suggests that individual buyers or sellers are often large enough to "move the market."

Because electricity does not fit the conditions required for efficiency under competition, it is necessary to develop market rules that improve the transparency of price information, constrain the ability of large buyers and sellers to move the market, and assure that

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[5] See, for example, Reynolds, Microeconomics, 1973, pp. 25 – 30.

adequate supplies are available when needed. Various approaches have been used to achieve these goals in the electric industry and other markets, and several alternatives will be discussed here.

5.4. Examples Of Successful And Failed Approaches

Traditional Market Rules: Full Regulation of Wholesale and Retail Service

Prior to about 1985, both wholesale and retail markets for electricity in the USA were fully regulated in all states. The characteristics of this regulation included:

- A reasonable expectation of being able to recover prudently-incurred investments made and expenses incurred for the delivery of reasonable, adequate and efficient service;

- Industry self-regulation of technical issues, such as voltage, frequency, resource planning and operating reserves;

- Economic regulation of prices at the wholesale level by the federal regulator, and economic regulation of prices at the retail level by state regulators;

- Quality of service regulation at the local level by state regulators;

- An obligation on the part of the utility to provide service to the public.

5.5. Stock Exchange Rules: Transparency, Manipulation, and Market Power

It is perhaps useful to look at how security exchanges regulate transactions in stocks and bonds. These are among the most transparent markets, and security regulation has focused not on price regulation, but on helping markets enable reasonably knowledgeable buyers and sellers to reach agreement on prices. The key characteristics of securities markets are:

- All transactions must be reported in real-time. The buyer and seller are not known (for small transactions), but the amount sold, and the price are reported immediately.

- Severe penalties (criminal and civil) for misrepresentation or withholding of financial information, manipulation of markets, and other transgressions;

- Strict regulation of "insider trading" by individuals who know "more than the market knows" about company finances;

- Requirements for immediate and simultaneous release of information to all market participants;

- "Circuit breakers" that interrupt unfettered trading when volatility of prices exceed thresholds that are determined in advance.

This model actually provides excellent guidance for some characteristics of workably-competitive electricity markets.

5.6. Early Utility Restructuring Rules: Inadequate Rules to Assure Competition, Predictable Prices, and Reliability

Early utility restructuring efforts, particularly in New Zealand and California, provide good examples of how inadequate rules can lead to failure to achieve the goals of reliable power at affordable cost.

New Zealand attempted to allow wholesale and retail markets for electricity to be completely unregulated, with a relatively small number of companies owning the overwhelming majority of the power generating facilities. The lag required for development of new power facilities (coupled with the recapitalization of the formerly government-owned generating system) led to sharp price increases through the 1990's. The lack of any obligation to provide for either long-range planning or continuing development of resources to meet growth ultimately led to a decline in system reliability by 2002-03. Finally, the government recognized the importance of system reliability and price predictability, and has initiated creation of an Electricity Commission in 2003, to re-regulate this industry.

California's experience was swifter and more catastrophic. The market design selected was to require the traditional distribution utilities to offer prices that were low enough that competition was stifled. In addition, a requirement was imposed that these utilities acquire 100% of their power at spot market prices. In response to a drought that reduced hydropower availability, short-term prices spiked beginning in May of 2000. The distribution utilities were faced with massive costs not reflected in prices. For months, the western states asked the Federal Energy Regulatory Commission to impose price caps, basically the type of "circuit breakers" that exist in securities markets. Eventually, the state's largest utility, Pacific Gas and Electric Company, sought bankrupty protection. Finally, after the FERC imposed a "must-offer" rule, imposed price caps, and state air regulators modified pollution rules, the markets returned to more normal conditions in June, 2001.

The lesson from both of these experiments is that market rules must be designed in advance to address "adverse" conditions, and to ensure that the necessary decisions to provide for reliable, adequate, and economic service are made in an efficient manner.

5.7. Norway: A Different Experience With Hundreds of Power Generators

Norway represents a relatively unique electric power market, one that has made a successful move to competitive wholesale markets. This is possible in Norway, in large part, because of the large number of small electricity generating companies, nearly all of which own and operate relatively small hydroelectric power projects.

Hydroelectric generation is unique in that it is extremely reliable, extremely dispatchable, storable (within limits), and in Norway, exists in relatively small increments compared with the national grid. The total grid in Norway consists of 28,000 MW of generation, coming from 740 separate hydroelectric generating units and a few thermal units. There are a total of 307 wholesale trading companies, many of which own generating facilities. 55% of the total generation is owned by municipal entities, 30% by the state, and 15% by private entities.

With less than 5% of the nation's power supply coming from a single project, and a relatively large number of producers, Norway comes closer than any other country to meeting the "many buyers and sellers" requirement for an efficient market.

There is little prospect of a similar situation becoming operational in Namibia anytime in the foreseeable future. A small number of hydroelectric projects are proposed along the Orange River, and some wind production in various locations is possible. The small load in the country, the size of the major existing power generating facilities in Namibia, the country's historic dependence on South Africa's large coal power plants, and other factors make it improper to compare Norway's competitive success with the type of wholesale market that is plausible for Namibia.

5.8. Market Rules For Namibia And Southern Africa

The essential topics to address in market rules are the same for Namibia and Southern Africa as for any interconnected region. The small size of the Namibia load, coupled with the relatively large size of individual generating units, creates some special considerations.

5.9. Financial Qualifications of Buyers and Sellers

Both buyers and sellers must have adequate financial capability to fulfill the contracts they enter into. Otherwise the contracts will be only as meaningful as the creditworthiness of individual purchasers and sellers, and will not be "fungible," that is, tradable between market participants in the same manner that stocks, bonds, or bushels of wheat can be traded. Further, a contract premium, extracted from a less credit-worthy trading partner, will distort the market, suggesting a higher value than would exist for "normal" trades.

The collapse of markets formerly dominated by Enron in the United States highlighted the importance of creditworthiness among market participants. Namibia can learn from this experience, but cannot afford to repeat it. A rational approach would be to limit power trading to parties with adequate financial resources to manage the volatility and risk associated with wholesale trading.

To some extent, markets can handle multiple different "grades" of creditworthiness, and price commodities accordingly. In the corporate bond markets, bond ratings guide this. In the mortgage money market, there are "A" borrowers and "B" borrowers. However, Namibia anticipates only a small number of buyers (perhaps 10 large industrial customers, plus 5 regional electricity distributors) in its wholesale market. A relatively small number of sellers is also anticipated – perhaps five from the breakup of ESKOM, plus a few in neighboring countries of Southern Africa. This is simply not enough diversity to support multiple markets for wholesale electricity. A simpler approach would be to limit the length of term that a less creditworthy buyer or seller can enter into.

The financial qualifications needed to be a buyer or seller in the long-term market may be different from those required to participate in the short-term market. Short-term transactions, by their nature, do not provide any assurance as to either price or availability beyond a short period of time. Therefore there may be buyers or sellers that have sufficient creditworthiness to participate in the short-term market, but not in the long-term market.

Namibia should consider financial qualifications for buyers and sellers that are scaled to the size and term of agreements that they seek to trade. Whether this should be done based on a standard financial credit rating basis (bond rating, for example), or an ECB-mandated standard is a decision that should be related to local policies and practices for extending commercial credit. Generally speaking, a firm with a solid credit rating, relatively high equity capitalization ratio, and supply base (for sellers) or customer base (for buyers) that is not volatile should be permitted greater flexibility in trading than firms with lower creditworthiness. A schedule such as the following, might be appropriate, or some other indices might be used:

Allowed Trading Products for Buyers and Sellers of Specified Creditworthiness

Bond Rating	Spot Market	1-Year	5-year	10+-year
AAA	Yes	Yes	Yes	Yes
AA	Yes	Yes	Yes	If 45%+ equity
A	Yes	Yes	If 40+% equity	No
BAA	Yes	If 40%+equity	No	No

5.10. Technical Rules for Power System Compatibility

Namibia needs to specify certain technical rules for the regional electricity distributors, for industrial customers buying in the wholesale market, and for power merchants. These must address issues such as scheduling, voltage, frequency, and other factors. The Wholesale Spot Market Rules of the Philippines, or the Electric Rules of Texas, both included in the CD appendix to this report, provide examples of the type of detail that is required.

One important rule for a system as small as Namibia is the process for load shedding and curtailability, needed to maintain reliability on any electric grid, and particularly important for a small system with a limited number of resources available to it.

Some entity must provide ancillary services, such as operating reserves, spinning reserves, load following, and black start capacity. That entity must be paid to do so. In some markets, industrial customers have sought to buy spot market power without contributing to these ancillary services, in order to secure lower electricity costs; this is an unrealistic situation, since curtailment of such customers has immediate adverse macroeconomic impacts on the community. The technical market rules must make clear whether the buyer, the seller, or a third party will be providing these services, and the prices to be paid for the services in association with each wholesale transaction.

5.11. Market Design

The design of wholesale power markets should encourage competition among sellers, competition among buyers, and provide sufficient information that buyers and sellers can reasonably compare available alternatives. To achieve this, there are two items of particular importance. First, the power products need to be standardized, so that they are comparable. Second, there needs to be sufficient real-time reporting of transactions that a transparent market provides meaningful information on prices to all market participants.

The goal of change should be benefits to consumers. Any form of market design that provides opportunities for market manipulation, for secrecy, or for confusing power products should be avoided. Those elements of power supply that do not lend themselves to competitive provision – primarily transmission and ancillary services – may be best provided by regulated entities.

5.11.1. Standardized Power Products

Electricity is different from most commodities in that it cannot be stored easily. However, it does lend itself to the same type of standardization as other commodities, and this can form the foundation of a viable electricity market.

A relatively simple comparison can be made between electricity supply and the tangible products offered in traditional commodity markets for petroleum products, grain, and metals. In each of these cases, the commodity markets provide for multi-year futures and options, so that a buyer can secure a predictable supply of a commodity of predictable quality, at a predictable price. While there will be a need for specific products, it is important that multiple vendors continuously offer to sell standardized products, as these may form a benchmark against which tailored products can be compared.

At a minimum, a viable market must include at least the following standardized power products:

- A standard product consisting of high load-factor multi-year power, such as that produced by a baseload power plant.
- A standard product consisting of high-load-hour multi-year power, such as that produced by an intermediate power plant.
- A standard product consisting of multi-year generating capacity rights with a variable cost component, such as that produced by a peaking power plant.
- A day-ahead energy market.
- A real-time spot energy market.

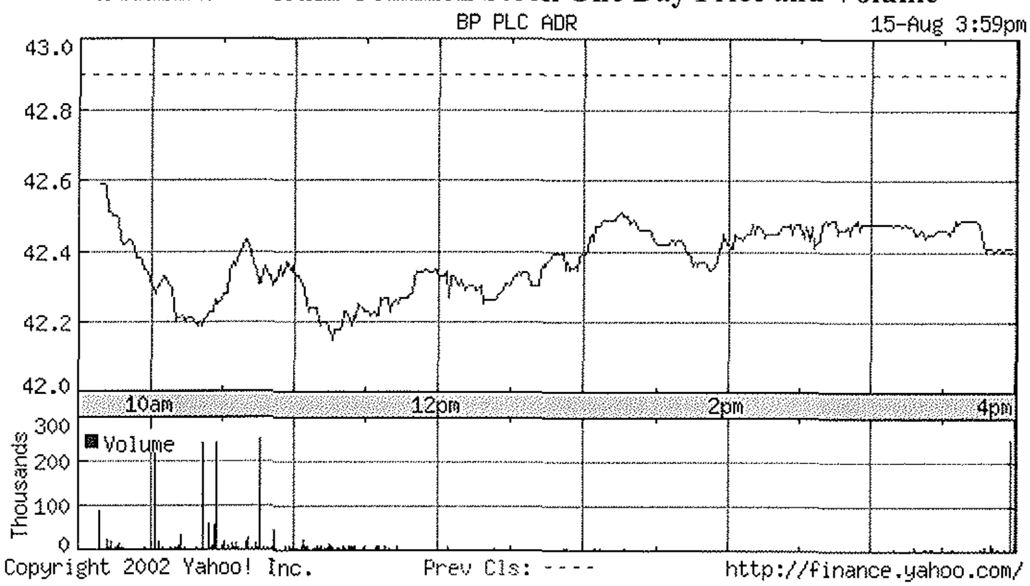
5.11.2. Reporting and Transparency

It is absolutely essential that electricity transactions be reported quickly and publicly. It is widely recognized that the market manipulation that occurred in California during 2000-2001 was possible only because buyers did not have adequate information about the status of the marketplace. The FERC decided to release ALL of the transaction data it had obtained in its investigation, in order to make that data available to the market for use by all participants. Had this occurred on a real-time basis, it is likely that much of the need for this investigation could have been avoided.

Other markets do provide for instantaneous release of transaction data. Stock exchanges all provide real-time data to the financial community. One knows how many shares of a particular stock sold at any given moment, and at what price. What is not known is the identity of the buyer or seller. This type of reporting provides buyers and sellers with continual data on market tendencies. Any withholding of transaction data – even for a few minutes – gives a buyer or seller an advantage in the marketplace, and this can be used to manipulate the market.

The graph below is an example of the daily transactions of the common stock of British Petroleum (BP) on the New York Stock Exchange. For each minute of the day, the number of shares traded, and the price at which they were traded, is made available to the public in real-time. The upper image shows the prices at which stock traded, and the lower image shows the quantities in each time period. On this particular day, there was relatively heavy trading in the beginning of the day, with price weakness, followed by light trading and price recovery. This information is available for every security traded on US exchanges, in real-time, for a subscription price of $10 per month or less.

British Petroleum Common Stock One Day Price and Volume



Not every transaction will be of a spot-market commodity, or of one of the standard products discussed above. For these, immediate disclosure of the pricing provisions and quantities involved is also essential for an orderly wholesale market to develop. Standardized reporting for non-standard bilateral contracts should be a specific market requirement.

The ECB may be the appropriate entity to receive notice of all transactions, and to compile the market data. Alternatively, the ECB might designate a different entity, either under contract to the ECB, or a different part of government, to compile and disseminate this data. This process should provide for the confidentiality of the names of buyers and sellers, but ensure that the details of each and every trade of electricity are reported to the public and all market participants in a timely and efficient fashion. Where the small size of the Namibia market makes it difficult to protect confidentiality while disclosing trade details, the process should err in favor of providing complete information to the market, rather that in favor of confidentiality.

5.12. Market Monitoring

A requirement for complete transparency of markets, with real-time reporting of all transactions will go a long way to reducing the need for market monitoring by the regulatory body. It will not eliminate it.

First and foremost, there is a need to ensure that all market participants meet the requirements with respect to financial and technical capability.

Second, the regulator should require that all market participants with "unlimited" trading authority (i.e., the ability to trade other than resources they actually own) post bids for standardized products with a maximum allowed spread between the bid and ask price. If this is done, these markets can serve as a benchmark for bilateral negotiations for specific products.

For example, if the regulator establishes standardized products for spot market, 1-year and 10-year baseload power products, and if all major market participants must post bids for these, the "order book" will be evidence of the market for power. For example, if the maximum allowable spread were $5/mWh, a bidder seeking to buy power might bid $30/mWh for a particular power product, but would simultaneously have to post an offer to sell the same product for $35/mWh. Every major market participant would then be filling the role that "specialists" fill for the stock exchanges: making sure that an orderly market exists, and also making sure that public information on pricing for standardized power products is available in order to serve as a benchmark for non-standardized products. If the market price for 1-year firm on-peak contract was $30/mWh, and that for a 10-year firm on-peak contract was $40/mWh, then any party negotiating a 5-year on-peak contract would be able to use these as guides to the appropriate price.

Perfect information, available to all participants, makes for efficient markets. That information is available to securities exchange participants by viewing the "order book" for any given security. The "order book" for Microsoft after the market close on August

15, 2003 is shown below; similar order books exist for all traded securities, and for commonly traded options:

Real-time Archipelago Order Book: MSFT Highlighted orders represent the best Bid and Ask orders from participating Institutions			
Bid Orders		Ask Orders	
Price	Order Size	Price	Order Size
25.54	600	25.55	3,800
25.54	173	25.56	500
25.50	300	25.57	1,454
25.47	1,000	25.57	2,000
25.46	1,000	25.57	5,000
25.45	1,000	25.58	500
25.45	1,546	25.58	4,000

In this "order book" all potential buyers and sellers can see how many shares are offered for purchase or sale at each price. Under these market conditions, no buyer would pay more than $25.55 if they wanted 3,800 shares or less of Microsoft. One can just as easily view this as the "order book" for spot market electricity. These prices could represent offers for 1-year contracts of baseload electricity, for 10-year contracts of high-load-hour electricity, or for any of the "standardized" products for which major market participants would be required to post bids and offers at all times.

Third, parties may trade power produced with "insider" information that gives them an unfair advantage in the marketplace. Policing insider trading is a major responsibility of securities regulators, and will be a continuing obligation for energy regulators. In the power industry, for example, the owner/operator of the only gas well in Namibia might "know" that the well was about to cease production for a period of time, when other market participants would not know that. If the owner/operator purchased short-term power futures, knowing that the sellers would need to revert to oil standby fuel to meet their obligations, they would be trading with insider information. Insider trading rules are important.

Strategic withholding of capacity was a significant problem during the California power crisis. An owner of 5 power plants might determine that by closing one of them, the market clearing price would increase to the point where they would receive more net profit from operating four plants than five. The FERC eventually dealt with this with a "must offer" rule for owners of capacity. A separate part of this collection of reports will deal with both the maximum amount of capacity a single seller should control for a market to be viable, and the minimum amount of "float" on the spot market that is needed.

The key elements to provide for adequate market monitoring are as follows:

- The regulator has access to all information held by all market participants.
- All transactions are reported in real time.
- All major market participants (those authorized to trade a wide variety of power products) must post bids for all standardized market products at all times, so that a vibrant market exists for standardized market products.
- Insider trading is severely punished.
- Any market participant with more than a small percentage of the capacity of the market must not be allowed to engage in capacity withholding.

Violation of the market rules, by any participant, should expose the violator to financial penalties that significantly exceed the potential benefit of the violation. The Board will need to have the authority to impose and collect these penalties, and to disqualify a participant from participating in the market if their violations are severe and/or continuing. In extreme cases of market manipulation, criminal sanctions may be appropriate, and the Board should establish a set of principles for when this step will be used.

5.13. Conclusion

This discussion paper has identified a number of major areas where specific market rules are required for an efficient, orderly, market that will serve the public interest. Specific market rules have not been proposed for Namibia, both because that exceeds the scope of this project, and because they should be developed jointly with the other members of the Regional Electricity Regulators Association.

The paper specifically provides for the type of rules in the financial qualification area, technical area, and market design area. It also identifies a number of specific elements that are needed to ensure a market that is vibrant and free from undue influence. It also provides the transparency needed for efficient participation by local electricity distributors, in the event that Namibia moves toward a competitive wholesale market structure.

5.14. Reference Material for this Section

Wholesale Electricity Market Rules: Let's Get Them Right (Edison Electric Institute

Standardized Market Design Discussion Paper, FERC (2002)

FERC Standardized Market Design 101

Comments on FERC SMD, Mid-Atlantic Consumer Advocate

Spot Market Rules Philippines

Market Monitoring Plan, PJM

Capacity Market Rules, PJM

Electric Rules, Texas Public Utilities Commission (Note: includes ALL Commission electric rules, not just wholesale).

Proposal to Establish and Electricity Commission, New Zealand

Norway System Facts

6. Purchase Power Agreements (PPAs)

Purchased Power Agreements (PPAs) are the legal contract between load serving entities (typically distribution utilities) and Independent Power Producers (IPPs) (typically owners of power generating facilities) that set forth the obligations of both parties with respect to technical, financial, and operational details for the sale and purchase of electricity.

Many utilities around the world have successfully used PPAs to secure needed capacity and energy for their systems. In a limited number of high-profile cases, however, the PPAs have been extremely controversial. The most notable of these was a contract between Enron and a state-owned distribution utility in India for power from the Dabhol power plant. In this case, the original contracted price was significantly above market levels, and the utility unilaterally defaulted on the contract. This became overshadowed by the overall collapse of Enron, but the incident indicated a set of risks that had previously been largely ignored by the financial community --- that a contract set at unsustainable and/or unaffordable prices is probably not a stable basis for investment. The flurry of litigation over power contracts in the wake of the California energy crisis of 2000-2001 is an indication that the India example may not be unique. PPAs today are being drafted in recognition of these risks.

Most PPAs or power sales contracts are long-term, fifteen years or more, full output contracts. PPAs have become increasingly complex documents that have grown over the past ten years from twenty pages in length to over two hundred pages. A typical agreement will specify the nature of the product being sold, the term for which it is being sold, the price(s) to be paid, and the operating relationship between the seller and the buyer. Since the Enron/India situation, PPAs also typically are very clear about what happens in the event of a default by one party, and provide protections against such default in the form of creditworthiness, governmental approvals, or other precautions.

Pricing terms are the most important. Electricity prices are either on a rolled-in energy basis (x/kWh) or two-part (y/kW + z/kWh) in nature. In either case, there may be performance standards (unit availability) tied to rewards or penalties. In general, the best practice is to have a two- part contract where the price components reflect the underlying cost of the technology being purchased. Thus a hydro plant and a gas-fired plant that are each expected to deliver power at 4/kWh would have different two-part contracts. The hydro plant would have a very high fixed component and a low variable component relative to the gas-fired plant.

There was a trend until the California energy crisis of 2000-2001 of a growing number of examples where merchant power plants were being constructed without long-term contracts. This was done by IPPs that had sufficient capital in hand or, along with their financing sources, had sufficient confidence in the economic, financial, and accounting operation of spot electricity markets or in the strength of retail competition to finance plants based on expected cash flow from direct sales to retail customers, sales to a spot market, or sales to a power pool. This development was interrupted by the energy crisis, and it is uncertain whether speculative merchant power will re-emerge or not. At a minimum, it will probably be limited for a substantial time to countries that have particularly clear, well-established, and stable electricity markets and underlying institutional and legal foundations that permit financing of this type. In the mean time, most IPPs will continue to be constructed primarily based on long-term contracts. These long-term contracts will themselves rest on the financial strength of the underlying purchasers, generally the local transmission and distribution companies.

PPAs need to be structured to meet the needs of all parties to the agreements, and also to meet the needs of the electricity consumers who are the ultimate source of revenue for the agreements. The seller needs a sufficiently certain cash flow to be able to service their debt, pay their operating costs, and have a reasonable expectation of a fair return to their equity investors. The buyer needs to have a dependable supply of power, a reasonable price, and the ability to integrate the power into a system that has uncertainties both as to loads and as to the output of the other power plants from which it receives power. Consumers desire reliable service at reasonable cost, insulated to some extent from the volatility of the unconstrained energy market.

An example of a recent PPA is provided in the attachments to this report. This particular PPA, between Montana Megawatts and Northwestern Energy, was downloaded from the FERC website, and selected only because it is both a recent example and a public document. It contains substantially all of the key elements to a PPA that are discussed below.

6.1. Structure of PPAs – term of agreement

Most often, the term of a PPA is sufficient to allow the seller to fully recover their capital investment. For a natural-gas combined-cycle combustion turbine, this will be 15 or 20 years. For a wind generator, microturbine, cogeneration facility, or other small generating unit, it might be a shorter period, while for a coal, nuclear, or hydroelectric power plant, it would typically be longer. A list of PPAs in which the lead author of this paper has been involved in the negotiation and/or regulation provides an indication of the range of possible terms.

Variability in Terms of PPAs

Seller	Buyer	Type of Unit	Term (Years)
Boeing Company	Puget Sound Energy	Gas turbine	4
Thermal Reduction	Puget Sound Energy	Solid Waste	5
Tenaska	Puget Sound Energy	Gas Cogen	15
BPA	Salem Electric	Wind	15
Spokane	Avista Utilities	Solid Waste	20
Vaagen Brothers	Avista Utilities	Wood Residue	20
March Point	Puget Sound Energy	Gas Cogen	20
Encogen	Puget Sound Energy	Gas Cogen	20
Pacific Power	Black Hills Power	Coal	35

The term of the PPA need not exactly match the accounting lifetime of the power generating facility. First, the accounting life is determined on an arbitrary basis, and may exceed the lifetime of the facility being built under local conditions that may cause equipment to fail sooner – for example, a marine environment. Second, the seller may be willing and able to take some risk regarding the final years of the project's expected lifetime, if the investment is sufficiently profitable in the early years.

Another example is where a seller may enter into one agreement for the sale of the output for the first five years of the plant life with one buyer, and then a separate agreement for the sale to another buyer after that. This is typical in the situation where the nearest load-serving entity does not have an immediate need for power. The seller may be willing to absorb higher transmission costs in the short-run to get the power to a market, but ultimately would prefer to sell the power closer to the facility and incur smaller transmission costs.

Sometimes agreements contain end-of-life provisions. These might provide that the buyer can renew the contract at a specified price at the end of the original term, or purchase the power plant itself for a specified payment. This provides some benefit to the original purchase for providing the cash flows that make construction possible.

The most common term of a PPA is for a conservative estimate of the plant lifetime. The buyer receives a high degree of confidence that they will receive power throughout the term, and the seller receives a high degree of confidence that they will receive sufficient revenue to cover their investment, and earn a profit. Shorter terms are typically only applicable where either the seller has a second customer for the remaining life, or the seller is well-capitalized and can absorb the merchant power risk of ownership.

6.2. Required guarantees in current financial environment.

In the current financial environment, investors in IPPs require some form of assurance that the contract will be honored. This includes certainty that the contractually obligated amounts will be able to be included in the price of electricity, and that the entire relationship is stable enough to survive financial, institutional, economic, and electoral changes.

In order to provide these assurances, it is essential that the country have a strong public utilities law, vesting authority in a strong independent utility regulator, that the PPA be subject to and consistent with the utilities law and any applicable regulations adopted by the utility regulator, and that the PPA be formally reviewed by the regulator prior to execution.

The review by the regulator can take several forms, ranging from review of the Integrated Resource Plan to formal pre-approval of the PPA itself. In the USA, pre-approval has generally NOT been the standard, and has been used in only a few states, and primarily in recent years. However, several notable disallowances of purchased power expenses have increased investor skepticism, and pre-approval is being re-examined in several states.

6.2.1. IRP Review

The simplest form of review by the regulator would be examination of the Integrated Resource Plan of the utility. This review would look at the generic types of resources that have been identified as optimal, and a decision approving the general acquisition of resources of a particular type, particular method of acquisition (ownership, PPA), and planned timing of resource additions. An example of this is currently underway in California for all of the utilities there, termed a "Long-term Procurement" docket.[6] It is not anticipated that this docket will result in approval of particular resources, or the pricing terms for those resources. The regulator's decision would provide guidance as to whether the proposed acquisition is the appropriate kind of resource, without rendering a decision on whether the actual costs incurred are recoverable.

6.2.2. Certificate of Public Convenience and Necessity

Some jurisdictions require utilities to obtain formal regulator approval before commencing development of a new resource (or even making significant life-extension investments in an existing resource.) In these dockets, the utility is required to present the explicit development proposal, including estimated fixed costs, the development timeline, and life-cycle operating costs. The regulator makes a specific ruling as to whether the resource may be developed or acquired. This decision does not necessarily

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[6] California PUC Docket No. R.01-10-024

bind the regulator to approving recovery of the costs of the resource, particularly in situations where the final costs may be significantly different from those estimated at the time that development was initiated. An example of such a docket now underway is the California PUC review of the rehabilitation proposal for the Mohave coal plant.[7]

6.2.3. Contract Pre-Approval

Contract pre-approval provides the highest level of investor confidence in a PPA. Under this approach, once the buyer and seller have finished negotiating all terms of a proposed resource transaction, the final contract is submitted to the regulator for review. If approved by the regulator, and the seller meets their obligations to deliver power, the regulator (and its successors, at least under stable governments) is obligated to include the costs in utility rates.

There is residual risk, because there is still not necessarily assurance that the utility will be able to sell the power, recover the costs through energy sales, and still be able to pay the amounts called for in the contract. That risk is normally deemed to be relatively small unless customers have unbridled ability to leave the utility system without having to pay an "exit fee" or otherwise bear a responsibility for stranded costs. With appropriate restrictions on customer migration, the principal risk is a general economic contraction that would leave the utility insolvent due to declining sales.

IPPs have a strong preference for contract pre-approval, as it provides confidence to investors that, as long as the parties to the agreement CAN perform, that the revenues needed to support the investment will flow from consumers to the utility to the IPP to the investors.

The time required for pre-approval can create problems for achieving this very certainty. The PPA should contain a clause providing that the contract is not valid until the regulator has approved it, and must provide for an adequate period of time for the regulator to review the contract. This might create a situation that, by the time the regulator has finished its review, the underlying costs might have increased to the point that the seller no longer wants to proceed, or declined to the point that the buyer no longer wants to proceed.

In the event that pre-approval is pursued as a part of the power supply procurement process in Namibia, it would be important to incorporate the types of guarantees that investors can provide and that consumers should expect. This would include:

- The power plant is owned by a developer with substantial assets in addition to the power plant;
- The developer has a strong credit rating;

[7] California PUC Docket No. A.02-05-046

- There is not a separate "shell" corporation established to own the power plant; It is a part of a larger group of assets, all of which can be called upon if necessary to meet the obligations of the contract;

- The technology being used is reliable, and adequate provision for replacement power during periods when the unit does not operate is provided for in the contract;

Similarly, investors should expect that pre-approval means that if the developer performs under the contract, the payment stream called for under the contract will not be subject to subsequent disallowance by the regulator.

These elements are designed to ensure that both consumers and developers are protected by a contract that has been approved by the regulator.

It is quite probable that in Namibia some form of pre-approval, or even government guarantees of loans, will be necessary to attract capital on reasonable terms. This issue is discussed in greater detail later in this section.

6.2.4. Post-Acquisition Prudence Review

The traditional role of the regulator is not to take a role in the decisionmaking of utility management, but rather to sit as a judge of the effect of that management. In this role, regulators have most often waited for the results of resource acquisitions to materialize, and then decide whether the acquisition was "prudent."

These reviews can be applied equally to utility-owned resources and to power purchased under PPAs. In some cases, these post-acquisition prudence reviews have resulted in significant disallowances by regulators of the amounts paid for power. A noteworthy recent case involves Nevada Power, a subsidiary of Sierra Pacific Resources. Nevada Power entered into short-term contracts for power during the 2000-2001 west coast energy crisis; a disallowance of $400 million was ordered by the Nevada PUC, and Sierra Pacific has faced a steep decline in its stock price, and a significant liquidity crisis, since this decision.[8]

Under Nevada law, short-term purchases are reviewed after-the-fact, while long-term agreements are subject to pre-approval. While this appears to respect the fact that long-term agreements can provide adequate time for regulator review, while short-term agreements cannot, it also biases the utility in favor of heavy reliance on long-term agreements, as these pose less risk to shareholders. This bias may preclude an optimal mix of resources to minimize costs and manage volatility.

In Namibia, leaving contracts to go into without regulatory review may create a degree of uncertainty that drives up the cost of capital for projects to unacceptable levels. While

[8] Nevada PUC Docket No. 01-11029

NamPower currently has a well-respected creditworthiness, entering into long-term contracts without regulatory review might impair that credit access.

6.3. Pricing in PPAs

The pricing terms of PPAs are typically designed to meet the needs of the buyers and sellers, which can be quite different. The seller needs a flow of funds adequate to cover their debt service in every year of the contract, and which generates a reasonable return on the investment. The buyer needs an initial price which is not out of line with market alternatives, and desires the flexibility to dispatch the resource to meet varying needs through the day and through the year.

A common form of contract with an IPP operating a natural-gas fired generating unit, for example, provides the seller with a fixed payment each month that is adequate to cover their debt service, but not provide a return to the equity investment in the facility. The buyer can then call on the output of the power plant whenever they choose to, and makes a variable cost payment for each kilowatt-hour received. The variable cost payment includes an adder to the variable fuel and operating costs of the facility, which provides the equity return. An example of this type of contract is provided in the reference materials to this report.[9]

The intent of this type of agreement is to give the seller a strong incentive to control its operating costs so that the power plant will be called on as many hours as possible, since they earn their profit only when the plant is actually used.

This type of agreement provides the flexibility that the buyer needs, provides some strong incentives for the seller, but may put the seller in direct conflict with overall social policies to encourage lower energy consumption. As long as the seller cannot really influence these policies, it is not a significant risk, but if an individual seller is large, relative to the size of the market, and has significant political power, it can be an issue. In a market as small as Namibia, it is possible that any economical-sized thermal power plant will be very large relative to the size of the domestic market. In this situation, it is crucial that the contract be structured within a larger multi-country power pool of resources where the market power of the seller will be minimal.

The fixed costs borne by the seller include debt service, depreciation, fixed O&M expenses, capital additions needed to keep the unit operational.

Fuel and some operating costs are variable costs. For example, while a maintenance staff to keep a power plant working are a fixed O&M expense, while the use of lubricating oil, water treatment chemicals, or other consumables are considered variable operating costs.

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[9] Capacity and Energy Sale Agreement Between Montana Megawatts I, LLC, and Northwestern Energy, LLC.

It is important that sellers facing liquidity crises and even bankruptcy (NRG and Mirant are examples) will not default on PPAs during the reorganization process if the variable payments exceed the variable costs. Conversely, if the variable payments are too small, they can run out of cash even after suspending debt service on their fixed cost payment obligations. A PPA should therefore have a variable cost payment that fully covers the actual costs the seller will incur, as otherwise the seller can run into cash flow problems that might preclude delivery of expected power.

6.4. Who provides spinning reserve, operating reserve, maintenance reserve?

An IPP typically owns only a single generating facility. These are subject to many different types of operating risk. There are scheduled maintenance outages, unscheduled maintenance outages, and periodic fuel supply interruptions (for example, if dependent on a single gas field or a single pipeline). A utility needs reliable power, and must maintain spinning and operating reserves for unexpected generating plant outages, and have adequate maintenance reserves for scheduled outages. In a PPA, it is important to specify whose responsibility it is to provide these types of reserves.

This is important in part because some wholesale market sellers may be multi-unit owners, able to provide a "system sale" from a portfolio of resources while an IPP may have only a single unit. Currently, Namibia relies on Eskom for the majority of its power, and Eskom has numerous power plants available to meet that obligation. In a well-designed power pool, there will be well-defined ancillary service markets established, so that an IPP can buy spinning reserves, operating reserves, and maintenance reserves at a reasonable price.

If and when Namibia moves from a single-buyer market to a wholesale market model, this will become even more important. In a market as small as Namibia, it is impractical for small regional electricity distributors to maintain a flexible enough set of power resources to be able to accommodate an IPP contract unless the required reserves are available and considered when deciding between competing alternatives.

6.5. Load Following and Load Shaping

Some types of resources, particularly wind energy, provide unpredictable levels of output from hour to hour. Others, such as hydro, provide unpredictable levels of output from year to year, or season to season. A buyer should not hesitate to acquire such resources if the expected output pattern matches their need. A well-developed power pool will have defined products available to provide these services, so that the owner of a resource with sporadic output can contract for load following and load shaping services. While the typical costs are not small -- adding as much as $.01/kWh to the cost of wind energy, they are also not prohibitive if high quality wind generating sites are available.

A PPA for any type of resource should specify whether load following and load shaping services are included or excluded. It is less of an issue for conventional resources than for resources with less predictable output. However, as an individual resource becomes a significant percentage of a utility's total portfolio, it becomes much more important.

6.6. What is penalty for non-performance of the seller?

Any PPA needs to include penalties for non-performance. The regulator should be primarily concerned about non-performance on the part of the seller, since the buyer is assumed to be a regulated distribution utility selling power at regulated prices to consumers that cannot easily escape the costs approved by regulators.

The types of non-performance include failure to provide the reliability of supply called for under the contract, failure to deliver the ancillary services called for under the contract, and failure to meet the pricing terms of the agreement. The former can occur if the generating facility does not work as expected, or if the third-party suppliers of ancillary services do not deliver. The latter can occur if the pricing terms protect the buyer from volatility in fuel or other operating costs, and those costs exceed the financial capability of the seller.

The penalty for non-performance should make the buyer whole. In the case of an unreliable resource, the cost to the buyer of replacing the expected service in the market should be the contractual responsibility of the seller. For example, if the project fails to deliver as expected at a cost of $.05/kWh and the utility must replace the energy at a short-term market rate of $.10/kWh, the seller should not receive the $.05/kWh expected to be paid. It should be further liable to the buyer for the excess costs of an additional $.05/kWh, plus any extra transaction costs required to make this arrangement. If this is done, the buyer is no worse off than if the contract had been fulfilled.

The buyer of power is protected from spiraling fuel costs by the option to not take delivery of power. It would normally still be obligated to make the fixed cost payments under the contract ($y/kw/year), but could choose to take no power and therefore make no energy payments for variable costs ($z/kWh)

It is possible that a resource will fail to provide the reliability called for under a contract, and replacement energy is not available at any price (for example, due to a transmission failure at the same time). In this situation, there is no market price to serve as the basis for compensation. The contract should include a default value for "liquidated damages" in the event of non-performance.

Finally, there is the risk of non-performance due to the financial inadequacy of the seller. The regulatory review of the PPA, at the time it is entered into, should seek to minimize the risk of this, but the potential remains. Some PPAs provide for the buyer to receive operating control and/or an ownership interest in the generating facility in this situation. This is probably of limited value, except in cases where the market value of the power significantly exceeds the contract price for power; this could occur if the seller had not hedged their fuel costs. It is important that the financial relationship between the IPP and their lender recognize this standing for the buyer, or else the normal course of insolvency would cause the facility to default to the lender, leaving the buyer with a valueless contract with an empty shell of a seller.

6.7. Mitigating the risks from the seller's perspective.

The price that an independent power producer will charge NamPower or a distribution utility in Namibia will be affected by risk. There is not only by the perceived technological and economic risk of the specific project, but also the perceived risk of doing business in a legal environment that has limited history with respect to contract enforcement.

The experience in India, with the Dabhol plant, has underscored this type of risk to the international financial community. The initial contract arrangement was guaranteed by the government. After the high costs became an obvious burden, the contract was then repudiated by the state-owned utility. The legal framework in India did not protect the seller's rights under the contract.[10] The aftermath of this experience is continuing to prevent other power producers from being willing to invest in India.

Conversely, in the United States, with a long-established legal framework, has dealt with similar high-cost contracts in a very different manner. Nearly all of the high-priced contracts entered into by utilities during the California power crisis have been upheld by the courts. Many utilities, including Southern California Edison, Pacific Gas and Electric, Seattle City Light, Snohomish Public Utility District, and others have been held to the terms of contracts for very expensive power. Most recently, the federal bankruptcy court ruled in favor of Enron and against Nevada Power and Sierra Pacific Power, upholding the integrity of the contracts, even though this may in turn cause the insolvency of the utilities that purchase this energy.

The types of risk that a seller is exposed to include non-payment due to insolvency of the buyer, non-payment due to contract disputes, and even such contingencies as nationalization. The cost of capital to the seller will reflect these uncertainties, and will be significantly higher unless these types of risks are mitigated. One form of mitigation can be provided by a government guarantee, but in the Dabhol case, this was not honored by the state. The perceived stability of the legal framework of Namibia will be a key factor in determining the level of risk that sellers must plan for, and the cost of capital they will incur.

6.8. Buy Versus Build Issues.

If a utility is able to choose between building its own resources, or buying output from IPPs and other market participants, there are a number of issues which must be considered in comparing these alternatives. Simple cost comparisons are often inadequate, due to failure to adequately identify the risks that remain with the utility under each alternative.

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[10] The contract itself was widely recognized to provide extremely high-cost power, far above any cost-based pricing.

Any PPA leaves some risk with the utility. At a minimum, the utility is left with the risk that the IPP will become insolvent and the power generating facility inoperative. While the utility would logically not need to make the payments called for under the agreement, it would be left with a sudden need to acquire replacement resources, possibly at much higher prices. Any premium paid in the early years of a contract, over the market price of power (in anticipation of a stable, below-market price in the long run) would be lost. Since owners of capital-intensive facilities need such payments to support their financing, this is a real risk.

The financial community views the fixed-cost part of the payment from a utility to an IPP as having some of the characteristics of debt. If the utility does not need the power, or if the power is uneconomic, the utility must still make the fixed cost part of the payment, as long as the resource is operating. In order to compensate for this risk, the rating agencies have required utilities to maintain higher equity ratios, to insulate utility bondholders from this risk. Thus, a PPA leaves some of the same risk that the utility would bear if it were the owner of the resource. In order to account for this, the price under a PPA must be slightly lower than the cost of power from a utility-owned resource.

Of course, if the utility owns a resource, and the resource fails for any reason, the utility (and ultimately, its shareholders and/or consumers) are left with the cost of replacement power. Often, regulators have allowed utilities to recover both the fixed costs of a utility-owned power plant AND the cost of replacement power, at least for a period of time, when a resource fails. A typical PPA, on the other hand, would provide for immediate cessation of payments if the resource does not operate for an extended period of time. Thus, it is generally acknowledged that IPPs absorb some risks of non-performance that do not apply to utility-owned resources.

As is evident, one cannot simply compare the "cost" of power under the "buy" alternative (contracting with an IPP) versus the "build" alternative (utility ownership of resources). The comparison must evaluate, among other issues, whether the utility is exposed to greater cost when the equity premium required by the rating agencies is accounted for, and whether the utility as a whole is exposed to more risk or less risk than were it to build the resources itself. This is not a simple comparison, and there are no easy tools to measure the relative risk.

6.9. The role of the regulator in balancing the interests of sellers, buyers, and ultimate consumers.

In examining PPAs, regulators have a variety of obligations to the ultimate consumers. Their goal should always be to ensure that a reliable supply of power is available at reasonable costs that are sheltered from volatility.

First, the regulator or government should establish a well-defined Integrated Resource Planning process to allow for the objective comparison of resource alternatives, including demand-side options. This is essential to make sure that the type of facilities that the utility will contract for (or build) are the optimal type of resource to minimize financial and other costs. As will be discussed in a later section of this report, this should include

Portfolio Management principles, to ensure that no single resource or contract represents too large a share of the utility's total power supply and to ensure that the pricing volatility does not create excessive risk for consumers.

Second, the regulator should establish a process for consideration of proposed resource acquisition that is well understood by all parties. It can include pre-approval, or only post-acquisition prudence review, but there should be no ambiguity about what standard is being applied, so that all parties can measure their risk appropriately. It should be recognized by the regulator that the level of risk that is placed on the seller determines the required return to the seller will be, and this in turn affects the cost of power to consumers.

Third, the regulator should establish minimum financial qualifications for sellers, and examine all PPAs to ensure that the seller has a high probability of being able to deliver under the agreement. If the agreement creates a significant probability of seller insolvency under adverse conditions, it leaves consumers exposed to risk if and when those conditions arise. Approval of the financial qualifications of a seller does not necessarily mean that the regulator has approved full cost recovery under the contract. These are separate issues. The first is directed at constraining the risk of non-performance; the second would allocate the remaining risk.

Fourth, the regulator should ensure that PPAs contain clauses that protect the utility in the event of seller insolvency. These could include a right of the utility to exercise a purchase option in the event that the seller's financial condition deteriorates below specified levels, or other approaches to assure continuity of operation in the event of seller inability to perform under the contract.

Fifth, to help attract competitive power producers, the regulator should create a framework in which a resource, once acquired by NamPower or a distribution utility, will be included in retail rates, and the revenues will be available to make required payments under the contract. Assuring a stable legal framework in which the contract rights of sellers is critical to assuring a reasonable cost of capital. In Namibia, pre-approval may be essential to creating the confidence needed to attract capital at reasonable cost.

Finally, the regulator should ensure that PPAs allocate the costs and benefits of a resource equitably over the life of the resource, so that there is not likely to be a situation where either the buyer or the seller will have a compelling financial interest in abrogating the agreement. If the costs are front-loaded, the facility will likely have a market value that exceeds the contract price for power after a few years, and the seller will seek opportunities to terminate the agreement. Conversely, if the price is too low in the early years, the buyer may want to abrogate the agreement. Either situation could create a complex legal battle creating additional cost and uncertainty for consumers.

6.10. Reference Materials for Purchase Power Agreements

Commission Order on Prudence Review of Puget Sound Power and Light Company, Washington Utilities and Transportation Commission, Docket UE-921262 (19th Supplemental Order)

Commission Order on Prudence Review of Nevada Power Company, Nevada Public Utilities Commission Docket No. 01-11029

Financial Impacts of Non-Utility Power Purchases on Investor-Owned Electric Utilities, USDOE Energy Information Administration

Capacity and Energy Sale Agreement Between Montana Megawatts I, LLC, and Northwestern Energy, LLC

Dabhol Power Plant History

7. Role of the Regulator Under Wholesale Market Structure

Under a wholesale market structure, the functions of the ECB would change somewhat from that under the Single Buyer structure. The primary change would be the division of regulatory oversight of the functions now performed by NamPower into functions performed by the various regional electricity distributors.

7.1. Reviewing Resource Acquisition Plans of Distributors

The most important change will be in the area of reviewing the resource acquisitions plans of the regional electricity distributors, as they would become responsible for evaluating resource options, and acquiring a resource portfolio.

The regulatory task would become greater, simply because there will be multiple managers of multiple resource portfolios, and all of them need to be examined for adequacy, reliability, predictability of price, and other portfolio management objectives. Importantly, it will be critical for the regulator to ensure that customer-based resources, including energy efficiency and demand-response resources, are fully incorporated into the utility resource portfolio.

Assuming that a single national IRP is created, with joint participation of all of the regional electricity distributors, this task will consist primarily of ensuring that the individual resource portfolios are consistent with the findings of the IRP, while still reflecting important regional differences and resource opportunities. The largest amount of work should logically go into creating and updating the IRP, and the tasks of evaluating the portfolios for consistency should be relatively straightforward.

7.2. Retail tariff design

The retail tariff design function will be largely unchanged by a move to a wholesale market structure. Prices will still be set to recover all costs of production, transmission, distribution, customer service, and system benefits elements. Because the emergence of a viable wholesale market will bring with it better definition of on-peak, off-peak, seasonal, and other cost differentials, it may become easier to set tariffs that more accurately differentiate between different cost periods, but that is only one of several important elements in retail tariff design.

7.3. Rules for Large Customer Migration to Direct Access

We have discussed above the importance of setting specific rules for large customers that may be allowed to migrate into a direct access wholesale market. These consist primarily of determining if either exit fees or re-entry charges are appropriate, ensuring that these customers provide for reliability services in a manner consistent with other customers, and determining if large customers should participate in system benefit programs. Both because of the significant size of this customer base, and their importance to the economy, this aspect of regulation is likely to be very important and potentially quite demanding.

7.4. Monitoring of Market and Market Power

The chapter of this report on Market Rules and Market Monitoring sets forth numerous guidelines for efficient operation of a competitive wholesale market. The most important of these are licensing of sellers (to ensure they can provide reliable products at agreed prices); ensuring that all transactions are reported fully and promptly in a public reporting mechanism; and developing the market monitoring and intervention practices needed to manage generator market power.

We believe that our recommendation that all "full-market" participants be required to continuously post bid and ask prices for standardized wholesale products will go a long way towards ensuring that minor market participants have the information they require to make efficient and cost-effective decisions. Active market monitoring, to control market power without disabling efficient market price signals, is a delicate task, however, and one that requires a high level of professionalism and the consistent application of predictable rules.

7.5. Transmission Access and Pricing

Transmission access and pricing issues will become more important regulatory issues, because the different regional electricity distributors have different transmission needs.

Transmission access is crucial to being able to access the wholesale market. In a sparsely populated country such as Namibia, there will be inevitable transmission limitations that will prevent one regional electricity distributor from accessing power supplies that may otherwise be least-cost for their needs.

With respect to transmission pricing, the regional electricity distributors will likely begin to "contest" transmission tariff setting in order to gain financial advantage for themselves. Those with high voltage service and/or close to the Eskom/NamPower backbone will argue that their costs are much lower than those serving more remote areas. Transmission pricing can also affect the value of distributed resources (including distributed generation, demand response, and energy efficiency resources) and will affect the locational decisions of new generating plants. The ECB will need to consider the cost basis for transmission services, in the context of national rural economic development policy and other applicable criteria. The difference between postage-stamp pricing for transmission and cost-based pricing can be dramatic.

The ECB will need to consider whether some sort of national cost-equalization mechanism is appropriate for those regions that do not have access to the entire SAPP system and the wholesale power suppliers it may eventually include. Countries such as Canada and Indonesia have dealt with issues relating to isolated load areas without transmission access, or subject to high transmission costs, and may be models for consideration in Namibia.

Detailed technical assistance on transmission access and pricing issues is beyond the scope of this Report. These issues need to be addressed on a regional issue by the

Southern Africa Power Pool, and the Regional Electric Regulators Association, and are, to a considerable extent, principally international issues, not domestic issues for Namibia.

7.6. Reliability Standards and Rules

As the responsibility for provision of power supply is dispersed among multiple decision makers, the risk of reliability issues emerging becomes more significant. In addition, if distribution utilities rely too heavily on either unreliable sellers, or spot market purchases, the stability of their power supply declines.

Reliability standards need to be addressed in a number of ways for the transition to a wholesale market model to not put customer energy supplies at risk.

First, the provision of adequate financial stability for power sellers, to ensure that they can deliver in accordance with their contracts, needs to be established through the seller licensing process.

Second, responsibility for providing spinning reserves, operating reserves, and other ancillary services must be well defined. The responsibility can be placed on either the sellers or the buyers, but should not be left unspecified. One disadvantage of imposing this responsibility on the sellers is that most will be outside of Namibia. One disadvantage of imposing this on the regional electricity distributors is that their loads are likely to be so small as to make it uneconomical to provide these services.

Third, customer-based resources, including distributed generation, demand response, and energy efficiency, are potentially important sources of reliability services. The regulator must ensure that market rules and reliability standards are developed to call forth these resources in concert with supply-side resources for reliability purposes.

Distribution system reliability issues, such as standards for distribution system component specification, may be valuable in a small country such as Namibia. By establishing such standards (voluntary industry standards may work adequately well), Namibia can ensure that when equipment on distribution systems fails, it is likely to be available somewhere within the country on short notice.

7.7. Licensing of Sellers

We have discussed above under Market Rules the issues relating to licensing of sellers. The ECB should work with other SAPP regulators to develop uniform standards for licensing of power sellers, so that power transactions across national boundaries can be entered into with confidence that sellers will perform. These include financial qualifications, provision of reserves and ancillary services, compliance with transaction disclosure requirements, and technical specifications for power transfers.

8. Is A Separate Namibia Power Pool Feasible Or Desirable, Or Should Namibia Simply Be A Participant In SAPP?

The total load of Namibia is less than one percent of the Southern Africa load. In most utility systems, the total load of Namibia is smaller than the economic unit size for new generating resources.

We have discussed above, in the chapter on Steps to a Wholesale Market, the reasons why the individual regional electricity distributors of Namibia are unlikely to be able to be effective as wholesale market participants. The same logic applies to the consideration of creating a power pool within Namibia.

This does not mean that the wholesale power purchasers and sellers within Namibia should not seek cooperative arrangements for use of each other's standby and reserve capacity under contingencies that demand inter-reliance. Such arrangements are normally desirable, and should be considered.

8.1. Size of Namibian market

The first obstacle to creation of a Namibian power pool is the small size of the Namibian load. With a peak demand that is less than a new dual-train combined-cycle power plant, it is simply not practical to insist that generating resources be built and owned in such small increments as to allow for a robust wholesale trading market within Namibia. Tt would be more logical for Namibian entities to be partial owners, or contract for partial shares, of major generating facilities. While many excellent opportunities exist for small-scale generation (hydro, wind, and CHP), Namibia is also considering the development of the Kudu gas field and an associated power plant that, by itself, would generate more than the total electricity needs of Namibia. It is an example of the type of resource for which a Namibian regional electricity distributor would logically seek only a small percentage contractual share.

8.2. Minimum size for a viable pool

The minimum size grid for a viable power pool would be indicated by the size of load that would permit economic generating unit construction without creating market power for any individual seller. Assume for discussion that the economical generating unit in Southern Africa is a 400 – 600 mw combined-cycle unit (as it is in most of the world), and that system reserve requirements for reliability are in the range of 10%. Under these assumptions, and if power plant owners were limited to a single generating unit, the power pool demand would need to be approximately 5,000 mw of demand before a single owner of an economic-sized generating unit did not have market power. If sellers were allowed to own more than one power plant, the power pool would need to be larger still.

One clear lesson from the California energy crisis was that the "Big 5" generators achieved an unacceptable level of market power when the system reserve capacity fell below the capacity ownership of these market participants. Some analysts have recommended that generation owners be limited to a single facility to address this issue.

The approach we have discussed in the Market Rules and Market Power chapter of this report addresses this in a manner that would not preclude multiple plant ownership, but would define market power as capacity ownership in excess of reserve requirements.

8.3. Minimum resource diversity for a viable pool

There are two ways to look at resource diversity. The first is the size of individual generating units relative to the size of the power pool; this is an indication of how dependent the power pool is on an individual generating unit or station that may be subject to economic, technical, or political constraints. The second is the diversity of fuel sources within a power pool; this is an indication of how dependent the power pool is on an individual fuel source that may be subject to volatility.

Consistent with our other indicators of reliability and market power, a power pool should not be dependent on an individual generating unit or generation station for more power than the normal reserve margin of the power pool. This will ensure that a failure of the unit or station does not, under normal conditions, threaten the reliability of service, and will have manageable impacts on market prices.

Fuel risk is somewhat different. The primary generating resources in southern Africa are coal and hydro. Coal is subject to environmental risk, which we have discussed in the section of this report on Single Buyer / IRP issues, but it is relatively immune to price risk, particularly when contracts are entered into for life-of-plant, life-of-mine, or other multi-year agreements. The largest risk is typically labor risk, as an industry-wide strike can affect multiple mines and multiple power stations.

Hydro is not subject to price risk, to international markets, or to collusion or hoarding by producers; water flows downhill with great reliability. However, it is subject to drought, which is much like labor risk for coal, potentially affecting multiple hydroelectric installations simultaneously. Indeed, droughts were the triggering events of the California and Brazilian energy crises of 2000-2001.

Namibia has very limited generation, but considerable diversity, with hydro, coal, and oil-fired generating stations, new wind and hydro sites under consideration, and the prospect of a natural gas generating unit if the Kudu field is developed. However, the size of Namibian generators relative to the diversity needs of a power pool are too limited to be effective governors of reliability and cost, as discussed in the preceding sections.

Reference Materials for Practicality of a Namibian Power Pool

Wholesale Power Market Platform, US Federal Energy Regulatory Commission

U.S. EIA Southern African Power Pool

Portfolio Management: Looking After the Interests of Ordinary Customers in an Electric Market That Isn't Working Very Well (Provided in Section 2)

Minnesota Wholesale Competition Report

Southern Africa Power Pool Annual Report

Texas PUC Wholesale Market Primer

9. Review of Possible Benefits of Alternative Scenarios

The goal of a competitive wholesale market, and multiple regional electricity distributors competing in that wholesale market is to achieve efficiencies that are not being achieved in the single-buyer market structure. If these benefits can be achieved in other ways, without the costs, risks, or institutional challenges of achieving these benefits through introduction of wholesale competition, it may be desirable to pursue other options.

The principal options available to Namibia include a traditional vertical monopoly with appropriate IRP and Portfolio Management tools, the single-buyer approach now being implemented, and retail competition.

9.1. Vertically-Integrated Utility

The principal advantage that a traditional vertical monopoly brings to Namibia is the economies of scale that go with providing service to a small load, a diffuse population base, and relative geographic isolation. NamPower has become a world-class utility, providing service that is both reliable and economical in world terms, despite having a small customer base, small generation base, extreme geographic and environmental conditions, and limited access to alternative sources of supply. With a total load that is much smaller than a typical "viable" utility, this is an impressive achievement. However, to some extent this has been achieved in part by virtue of access to very low-cost generation from Eskom, driven by the excess capacity on that system. It is widely expected that as this source of supply dries up, that NamPower and Namibia will be facing significant increases in wholesale power cost.

Because of the existing arrangement, where NamPower is the wholesale supplier to municipalities owning their distribution systems, we do not anticipate NamPower growing to become the distribution utility in places now served by local entities. Therefore the concept of an integrated monopoly would be assumed to take the current form, with NamPower serving as the wholesale supplier to municipalities, and the retail supplier to other areas of the country.

If the movement toward creation of regional electricity distributors were to be halted, and NamPower were to be designated to continue to provide vertically-integrated service, implementation of the IRP mechanism discussed in the Single Buyer chapter of this report becomes even more essential. Given the expectation of rising prices from Eskom (or its successors) as excess capacity becomes more fully utilized, NamPower will (if it continues in the portfolio manager role) be in a significant resource acquisition mode in the future. Having the capability to evaluate alternative resource portfolios is essential for the vertically-integrated utility, in this case, NamPower.

9.2. Single-Buyer Structure

The Single-Buyer structure now being introduced may be most appropriate for Namibia. The NamPower portfolio manager will be acquiring resources to serve a total load of about 350 mw, quite small by international utility standards. It is, however, probably large enough that a diverse portfolio of owned resources, contracted resources, system purchases, and spot-market purchases can be assembled if NamPower adheres to prudent portfolio management practices.

There are two keys to success of this model in producing economic benefits for Namibia. The first is development of a comprehensive IRP process, as discussed in the Single Buyer / IRP chapter. The second is a commitment on the part of NamPower, the ECB, and the Ministry to support effective demand-side management and energy efficiency programs.

9.3. International Single-Buyer / Portfolio Manager

One option to consider might be having an international firm that specializes in energy portfolio management take responsibility for managing the supply portfolio for NamPower and/or the regional electricity distributors. The most likely entity would be one of the Eskom spin-off companies, if that proposal comes to fruition.

Each would be managing a portfolio of 5,000 to 10,000 megawatts of generation, a large enough portfolio to have real diversity, maintain reserves economically, and sufficient scale to render the administrative costs virtually irrelevant. The incremental cost of managing Namibia's load would be negligible.

As a practical matter, this option will not emerge unless and until Eskom is broken up, and multiple entities are operating in South Africa. This is several years away, at a minimum. It would not be prudent to delegate this responsibility to Eskom, since it is (virtually) the monopoly power supplier to augment Namibia's limited domestic generation. Namibia may be reasonably skeptical of delegating a function as important as electricity portfolio management to a foreign firm under any circumstances, given the importance of electricity to a growing economy. In addition, provision would have to be made to ensure that cost-effective demand-side and distributed resources were fully and fairly considered within the portfolio management process. This is an important national objective that would have to be met by any Portfolio Manager, whether from inside or outside of the country.

9.4. Retail Competition

It is currently not pragmatic to consider retail competition as an option in Namibia, as no infrastructure for competitive provision of power could reasonably emerge in a utility system of this size. If South Africa introduced retail competition in the future, it might be possible that vendors would eventually emerge that could then expand into Namibia, but such an outcome is years in the future, at a minimum.

Given the experience in most parts of the world that have experimented with retail competition, and the small size of the Namibia power market, we do not think that further examination of this option is timely. It is not practical for competitive retail suppliers to emerge in Namibia alone.

10. Learning Curve Issues

Any transition of the utility framework will bring unexpected results, and not all of these will be desirable results. One way to minimize the adverse impacts of change is to move gradually, evaluate impacts on a regular basis, and be prepared to quickly change direction if a situation becomes untenable.

10.1. Controlled Experiments

Controlled experiments are efforts to test new concepts in a way that is designed to provide research results, without necessarily affecting customers in a beneficial or adverse manner. These can be done through various approaches to research design, in which customers may or may not be aware of such programs.

An example of such an approach is to offer different customers different marketing information about energy, energy efficiency, or load management, but not subject them to different pricing, to economic penalties or rewards, or other financial inducement related to the measure being tested. In this manner, it is possible to test consumer response solely to "moral suasion" without a specific pricing incentive. One group of customers could be provided with time-of-use meters and information, but not time-variant pricing. One group could be encouraged to invest in efficient lighting or refrigeration, and another not subjected to the same promotion.

In order to get customers to participate in a controlled experiment, it is sometimes necessary to offer an inducement to participate in a program, but the inducement should be unrelated to the energy usage pattern or purchasing behavior that you are trying to modify. For example, giving every customer a free compact fluorescent lamp for participating in a survey about time-sensitive pricing, regardless of which group of questions they are asked, what answers they provide, or what action they take as a result of their participation would be an unrelated inducement that would encourage people to participate, but not bias their behavioral response.

Because of the geographic diversity of Namibia, and limited media markets, it is very easy to target specific areas with different messages, and measure the impact.

10.2. Implementing Pilot projects and Programs

Pilot programs would go one step further than controlled experiments, actually offering financial inducements to customers to change their energy-related buying decisions. As the IRP is developed, it will be evident that some efficiency measures are particularly good values for Namibia. It may be appropriate to develop one or more proposed approaches to achieving these savings, and test them on different populations. A pilot program would make a specific incentive available to all customers in a given geographic area, customer class, or other defined group.

There is a large body of international experience operating energy efficiency and load management programs that can be drawn upon in designing programs for Namibia. Some of these will be inapplicable due to climatic or cultural differences, but many will be very applicable. Testing some of these alternatives through pilot programs, and then drawing conclusions about the degree of success than could be expected from wide scale implementation of programs on a regional or national basis can be very valuable.

It may be much more difficult to test such things as allowing one regional electricity distributor to engage in wholesale purchases for their own portfolio, since the entire issue of whether it is advisable is so dependent upon the emergence of a viable wholesale market within SAPP. While the City of Windhoek is an obvious candidate for this, since it represents the largest municipality, largest load, and has access to the largest pool of expertise, even Windhoek is not a viable wholesale purchaser until a reasonably competitive wholesale market evolves in Southern Africa.

10.3. Risk Management – Developing capability before taking major risks.

Implementing energy portfolio management capability, initially within NamPower, and possibly in the future within the regional electricity distributors, needs to proceed with a system of checks and balances to ensure that adequate knowledge and capability is present before major risks are undertaken.

There are simply too many international examples of energy industry participants plunging into a world of unstructured "competition" in a goal to achieve uncertain economic benefits to not be cautious. As this is being written, energy sector participants in India, Indonesia, New Zealand, and the United Kingdom are facing extreme uncertainty, more than a dozen utilities in the USA have suspended or curtailed their dividend payments, and major market players like Mirant and Enron are in bankruptcy proceedings.

The ECB should consider implementing some short-run limitations on NamPower's actions as a single-buyer, to prevent a large, long-term obligation for a major resource without fully developed Integrated Resource Planning and adequate ECB review. This should not preclude any opportunity from being explored, but limit execution of an agreement without Commission approval. An appropriate threshold would be in the 25 – 50 megawatt range, for a 5+ year term. An example of this is the requirement for the Bonneville Power Administration to obtain approval from the Northwest Power Planning Council for long-term acquisition of resources over a certain size. This pre-approval is not required for energy efficiency investments, for small generating resource acquisitions that are determined by the Administrator to be consistent with the approved IRP, or for short-term resource commitments.

Once the IRP rule is in place, and the initial IRP itself has been developed, the Commission might relax the pre-approval condition suggested here, at least for measures that are unambiguously consistent with an approved IRP. A component of the IRP should be a two-year action plan, and once the IRP and Action Plan are approved, there may be no need for Commission review until an appropriate tariff proceeding for resource acquisitions that are consistent with the IRP and Action Plan.

As the performance of NamPower as a single-buyer gains experience, the ECB should periodically review that performance to see if appropriate portfolio management techniques are being applied, and take actions to ensure that the portfolio management tools are improved as necessary.

Consideration of transferring the portfolio management responsibility to the regional electricity distributors should be considered only after a period of experience with NamPower's performance as a portfolio manager is evaluated. Initially, that evaluation should be undertaken at least annually.

If the ECB determines that the skills needed to be effective portfolio managers are transferable from NamPower to the regional electricity distributors, and determines that the market has evolved to the point where power transactions of the size that the regional electricity distributors will enter into are subject to effective competition in the marketplace, then and only then should the Commission consider opening a process to determine if the potential benefits of moving to a wholesale market model are promising.

11. Questions On Practicality of a Wholesale Market Posed by ECB Staff

11.1. Is it practical to move a wholesale market model in Namibia?

This issue of whether it is practical for Namibia to move from a single-buyer market model (with NamPower providing electricity portfolio management services to all electricity distributors) to a wholesale market model (with the electricity distributors responsible for their own power supply decisions) is dependent on at least two key issues.

- Is a competitive wholesale market in Southern Africa in existence and equally available to all electricity distributors?

- Are the electricity distributors large enough to have efficient portfolio management capabilities?

In attempting to answer the above questions it is useful to begin with a definition of what is meant by the term "wholesale market" in order to have a common understanding of the underlying concept being considered in this particular case.

A wholesale electricity market is a competitive market, either in the form of a power pool or in the form of power exchanges, where competing generators (sellers) and large power users (buyers) interact to determine electricity prices on an hourly, daily, weekly, monthly or yearly basis.

The two types of wholesale markets are illustrated in Figures 1 and 2

Figure 1 – Power Pool Model

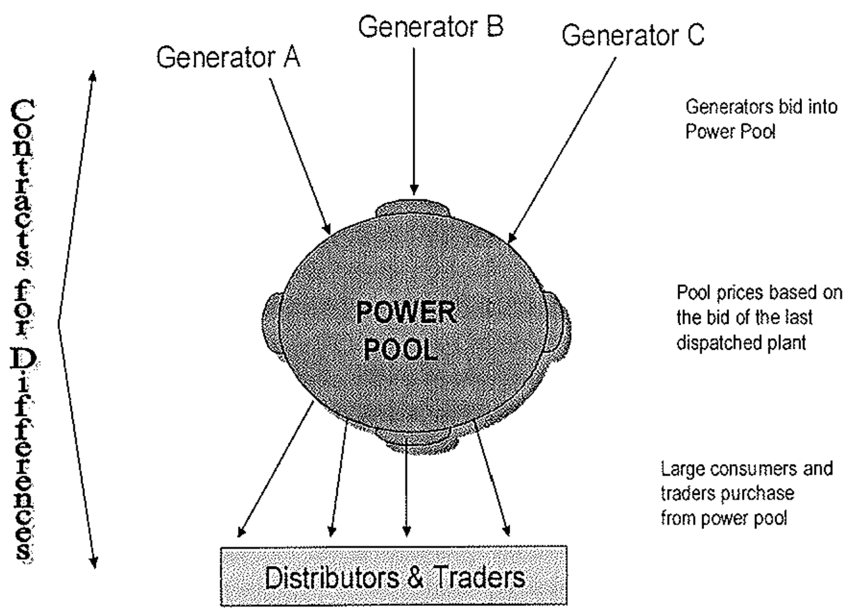
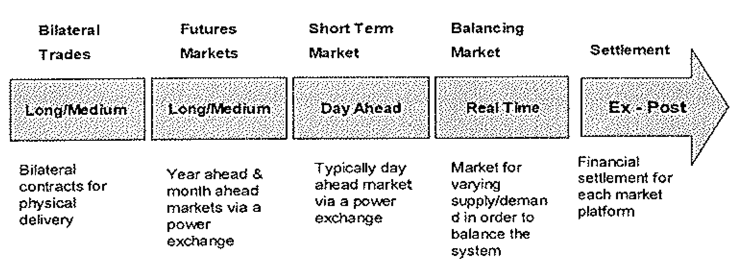


Figure 2 – Multi-Market Model



The present and future structure of the Namibian electricity industry will determine the feasibility of an indigenous wholesale market. Currently the Namibian Electricity Supply Industry (ESI) is vertically integrated up from generation (3 power stations with a total capacity of 392 MW) to transmission. Distribution/supply is in the hands of 40 odd local authorities who are being amalgamated into 5 regional distribution companies over the next 2 years. NamPower has been instructed by the government to fulfill the single buyer function for the ESI. Government envisions the single buyer as a transitional step towards wholesale. This transition period is envisaged to last between 5-8 years, after which a competitive wholesale (in a form as yet undetermined) is supposed to emerge. An alternative school of though sees the single buyer evolving, within the transitional phase, into the Namibian wholesale market platform(s), in other words evolving into the market operator.

The existence of a competitive market presupposes the existence of multiple sellers (generators) and buyers (distributor, large power user and traders). Are these conditions present in Namibia presently and in the foreseeable future? It is useful to disaggregate the equation and analyse the two components (sellers & buyers) separately in order to arrive at a substantiated conclusion.

11.1.1. Are there enough buyers and sellers for efficient results?

An efficient wholesale market must meet all (or most) of the preconditions for efficiency under market competition. These preconditions include:

- Identical products,
- A large number of buyers and sellers,
- No buyer or seller large enough to move the market,
- Capital that can move from one productive use to another quickly and easily, and
- Perfect information flow between market participants.

We assume that the first of these, identical products, will be defined by market rules established by the Southern Africa Power Pool (SAPP), with respect to voltage, frequency, and responsibility for reserves, so that any product offered has well-defined and understood technical characteristics. The fourth of these – fungibility of capital – is the most difficult, since electricity production by its nature involves specialized machinery that cannot be built quickly nor used for any other purpose. The last of these, perfect market information, is addressed in the section of this report on Market Rules and Market Monitoring. We also assume that NamPower (or its successor) will provide transmission services to all electricity distributors on a non-discriminatory basis, subject to technical and geographical constraints.

This leaves two issues: the number of sellers and buyers, and the extent of their market power.

11.1.1.1. Competition in generation

Namibia has three generation stations owned by NamPower. Ruacana hydro-electric station has the largest capacity at 249 MW, while followed by Van Eck coal fired station

(120 MW) and Paratus diesel fired station (24 MW). Ruacana, being fully amortised and with very low fixed and variable operating cost, is able to compete price-wise with Eskom or any other generator in the region. The other two cannot on their own, but are kept in operation due to the ancillary services the provide to the system in terms of the SAPP Operating Rules. Their value to the system is the fixed capacity/ancillary payments and combined with 394 MW of cheaper "system energy" that the existence of the generating plants give NamPower. If the two thermal stations were not available to the system NamPower would only be able to purchase 149 MW of "system energy" in terms of the SAPP Rules). Thus the three power stations complement rather than compete with each other, more so because they are owned by one company and there are no policy directives from government to un-bundle or privatise NamPower ("the goose that lays the golden eggs").

IPP's may be seen in some quarters as a means of introducing competition in generation. However the only possible IPP's in Namibia are at Kudu (750 MW), Lower Kunene (350 MW) or Popa Falls (20 MW), and perhaps some wind generators. Each of these potential projects face unique sets of intractable hurdles, raising serious doubt as to their immediate (5-15 year) fruition. Moreover it is unlike that IPP would ever be able to compete against incumbent generators at base-load or mid-merit and would therefore have to be specialised niche players (peaking, exports and ancillary services), a state of affairs that would seriously complicate their project financing

The final option would be regional competition in generation across Southern Africa, a more realistic scenario but one that is tempered by numerous imponderables. These include, specifically the pace of un-bundling Eskom, the development of new generating capacity in the region, regional transmission constraints, and the future direction of market reform (in South Africa and in the SADC region). Empirical evidence from SAPP trading performance in its 6 years of operation does not give much reason for optimism about the regional competitive scenario. 95% of SAPP electricity trading is conducted through bilateral contracts (mainly between Eskom and the respective inter-connected utilities), with little perspectives of this changing significantly in the near term (3-8 years).

South Africa has indicated an intention to divide Eskom into several companies, as part of developing a competitive wholesale market in Southern Africa. If this occurs, there will be multiple buyers and sellers, but it remains to be seen if they will truly be independent, or whether collusion will continue between these entities. Experience in other countries suggests that independence cannot be assumed.[11]

Even with the division of Eskom into five separate entities, power trade in Southern Africa would be dominated by perhaps eight entities – the five Eskom spinoffs, plus the

[11] For example, British Columbia Hydro severed its wholesale arm from the retail utility in 1988; many market participants have questioned whether Powerex is really independent of the utility.

national utilities of Zimbabwe, Zambia, and Mozambique. With projected transmission improvements, Angola and the Democratic Republic of Congo would join this group.

Experience in California during the power crisis of 2000-2001 showed that when a single market participant owns as much as 10% of the capacity on the system, market manipulation is possible. When the market in California tightened to the point that a single owner of multiple power generating stations could increase their total revenue by reducing their output, it appears that several took that opportunity. There are two lessons from this experience. First, one cannot depend on wholesale competition to produce efficient results if a single supplier owns enough generation to "move" the market. Since the current proposal would leave each of the Eskom spinoffs with more than a 10% market share in the region, it would appear to create the same kind of risk.[12] Second, wholesale competition is unlikely to produce efficient results unless customers are given the opportunity to reduce consumption in response to market price signals during moderate-to-severe price spikes.

By contrast, Norway is often cited as an example of successful wholesale competition. In Norway, there are hundreds of individual power generating entities, and only a few percent of the country's electric resources are held by a single owner. Further, Norway is interconnected to the Western Europe continental grid, where massive amounts of generation owned by dozens of separate owners exist, further constraining the market power of any individual participant in the Norway market.

The lessons from California are that no seller should control more than a few percent of the market, and active demand response should be an integral part of the market design. For example, if each of the California sellers had controlled only an individual power plant, none could have increased their revenues by strategic withholding of power. Given an assumption that the system must have 5% - 15% reserves in order to provide reliable service, holding individual sellers to less than the amount of capacity represented by normal reserves would appear to prevent strategic withholding. If reserves were 10%, and the largest seller held only five percent, a decision to reduce output would be quickly filled with other suppliers, and little market price movement would occur. Similarly, if an additional 10% - 15% of demand could have been subject to curtailment through a set of demand response programs, it would have the same effect on market power during a period of strained capacity as would additional generating reserves.

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[12] We should note, howver, that a ten-percent market share may not be enough to confer market power, if there is sufficient competition along all points of the supply curve (baseload, intermediate, and peaking). Market share by itself may not reveal whether market power is present – other characteristics of the market matter as well. Argentina, for example, has approximately 40 companies competing in the generation market, a couple of which have about ten percent of the available capacity. However, there is no evidence that these participants have or are exercising any market power, because at no point along the supply curve do they possess enough capacity to move the market.

A minimum of ten major sellers of power, none with a market share in excess of ten percent, would create a plausibly efficient wholesale market for sellers of power. Twenty or more sellers (similar to Norway) would be expected to produce a competitive market. Breaking Eskom into five entities, and introducing wholesale power from neighboring countries with small systems, does not meet this test.

11.1.1.2. Competing Buyers

Given the sparsely populated nature of Namibia, the REDs are being established as monopoly distributors in their respective geographic areas, and there is little or no scope for competition in distribution. Large industrial customers would probably want to purchase directly from generators wherever these may be located in the region, giving rise to some competition for scarce generation. Two poignant examples are currently in existence. The Skorpion Zinc smelter (80 MW) which buys directly from Eskom and only uses NamPower as a transmission carrier. Walvis Bay municipality which offers its high load factor large customers tariffs slightly lower than NamPower because of the overall value they bring in flattening the town's overall load profile. However electricity supply competition is predicated on the imponderables listed in the regional generation option above being clarified or resolved.

The issue of whether the regional electricity distributors are capable of managing their own power supply portfolios in an efficient manner is completely separate from the existence of a competitive wholesale power market. This report will examine the characteristics of a portfolio manager that can be compared to the capabilities of the regional electricity distributors.

11.1.1.3. Summary of Practicality Discussion

There is very little scope for a competitive market in the domestic electricity industry due to its structure and small size, leaving a "plug-in" to the regional market (currently in an embryonic stage) as the only viable option. However it must be realised by all role players that a fully functioning regional market is still a long way off (5-10 years). Nevertheless it is a cause for optimism that South Africa, the regional powerhouse, has begun taking its first tentative steps towards creating a competitive electricity market. It must be affirmed that competition, if effective, has the multiple benefits that prices are driven down to their lowest economic level, incentives to improve efficiency are sharpened, investment decision are subject to the associated risk, and innovation is stimulated. Furthermore where competition is possible it is always preferable to regulation

As a practical matter, if South Africa wanted to damage the economy of Namibia, it could do so through Eskom by bidding up wholesale power prices (through strategic withholding, as long as it owns the capacity), driving Namibia's wholesale power costs to untenable levels. Similarly, if a single large generating resource were developed in Namibia seeking to sell into the wholesale market, Eskom could saturate the market with surplus power at prices that would destroy any potential profitability of the developer.

11.2. What are the expected benefits of wholesale competition?

The primary expected benefit of wholesale competition would be a "bidding down" of wholesale electric prices to short-run marginal cost levels, and, over the longer term, increased generator efficiency, improved generation technology, and introduction of demand response resources into the power supply mix. The current resource mix of southern Africa consists overwhelmingly of coal and hydro resources, with very little in the way of resources with higher operating costs such as gas combined-cycle or simple-cycle generation. Consequently, the short-run marginal cost at almost any hour is likely to be the fuel cost of a less-efficient coal unit. An example of this is the Windhoek power plant, which has a high unit fuel cost due to fuel transportation expense.

Given the current surplus of generating capacity in Southern Africa, this would likely result in very low prices during nearly all hours. At the present time, Eskom is selling power at prices that are very attractive, but still above variable running cost, and thereby generating a meaningful contribution from these sales towards recovery of its fixed costs.

New power plants will not be constructed in an environment where the market price is significantly less than the long-run marginal cost of building and operating new units. At some point in time, projected to occur in the next 5-7 years, Southern Africa will exhaust its surplus capacity, and short-run marginal costs are expected to rise toward equilibrium (long-run marginal cost) levels.

Under conditions of equilibrium, the principal advantage of a wholesale market is that different producers will strive to be more efficient, and that will hold the price of power supplies lower than if monopoly suppliers remain dominant.

11.3. Should the 5 regional distributors be cooperating or competing in energy resource acquisitions?

11.4. Are the 5 Regional Electricity Distributors large enough themselves to be pool participants.

These two issues are addressed together.

Competitive wholesale markets (or markets that appear competitive under non-stressed operating conditions) have emerged in North America, in Western Europe, and also in Australia and Argentina. Each of these markets is characterized by a large number of large market participants. All have suppliers with several thousand megawatts of generation, and electricity distributors with several thousand megawatts of load. Within such a market, where no buyer or seller is large enough to significantly affect market conditions, it is quite plausible to add any number of small buyers or small sellers to a large market and each will be able to compete within the structure of the larger market.

As discussed above, the five regional electricity distributors of Namibia collectively account for only about one percent of Southern Africa electricity demand. Assuming that about 250 megawatts of Namibian demand would be served by these five distributors, the average demand of each would be about 50 megawatts. A typical unit of trade in wholesale markets is 25 megawatts, sold for either "high load hours" or "all hours." The variation in electricity demand for distributors with a total load of only 50 megawatts will probably not vary in increments that are common units of trade in efficient wholesale electricity markets. Therefore, it is likely that the individual regional electricity distributors will either be dealing with sub-market participants (brokers that divide economical-sized market purchases for resale), or else joining together to have sufficient demands to participate effectively in wholesale markets.

The same logic applies to effective participation in the Southern Africa Power Pool. If the typical transaction size in the Pool will be units of 25 megawatts or more, the five Namibian regional electricity distributors will be dealing with usage variations that are smaller than the typical transaction size of competitive wholesale markets.

As a practical matter, the operator of a control area is the entity that dispatches generation to meet load variations. While rural, non-integrated systems of less than 300 megawatts operate as individual control areas, it would be highly unusual for any electricity distributors the size of those anticipated in Namibia to operate their own control areas. Since some larger and more central entity will probably be responsible for dispatch of resources, it is difficult to envision circumstances under which a component of a control area would function as an independent power pool participant.

There is another reason for the distribution utilities to cooperate in power supply operations. Developing a portfolio of power supply resources and participating in regional power pools are complex tasks requiring detailed analysis, professional judgment, and highly skilled analysts and managers. It is also time consuming and expensive to acquire needed data, build professional relationships across a wide geographic area, and develop the legal and contracting expertise to enter into new supply arrangements with existing and new suppliers. By coordinating their power supply operations, Namibia's distribution utilities can more readily support the kind of staff and analysis needed to secure a reliable, stable, low-cost resource base.

It appears that the five regional electricity distributors, at least until they grow significantly, will be better served by cooperation in purchasing on the Southern Africa market than by competing with each other. Similarly, as long as their load variations remain small relative to the size of a typical wholesale transaction, they will probably be more effective by participating through a joint intermediary (such as NamPower) than by engaging directly in wholesale trade within the Power Pool.

11.5. Could a competitively bid resource acquisition scheme work just as well (or better?)

One alternative to wholesale competition (where the five regional electricity distributors participate in power pool marketing and scheduling) might be for the regional electricity distributors to solicit competitive bids to meet their wholesale power demand. This would differ from market operations in that the vendors would be bidding to supply an unpredictable market, and would take on the risk of those variations, rather than leaving that risk with the regional electricity distributors.

Good examples of this type of arrangement exist in the states of New England, in the northeastern part of the United States. Many of these states (Maine, New Hampshire, Massachusetts, Rhode Island, and Connecticut, have initiated retail competition programs. Participation in customer choice is very limited among small electricity users, and the local electric distribution companies continue to provide "default service" to nearly all of the small consumers. In several of these states, the distribution utilities have "bid out" the provision of default service, receiving proposals from multiple suppliers to meet the "default" loads. The sixth state, Vermont, has not moved to retail competition, but even there, some of the distribution utilities have bid out a major portion of their power supply needs.

The five Regional Electricity Distributors could solicit proposals from multiple vendors to meet their respective service requirements. Likely bidders might include NamPower and each of the five Eskom derivative companies. We are concerned that the limited number of potential vendors is small. However, this approach is more likely to produce a successful result for five small electricity distributors than asking each of them to develop an electricity supply portfolio independently that includes baseload, intermediate, peaking, and reserve resources.

The reference material for this chapter includes two analyses of the provision of default service, which in turn contain extensive discussion of the methods that can be used to competitively bid the obligation to supply power to uncertain load levels. These include:

> *Portfolio Management: Looking After the Interests of Ordinary Customers in an Electric Market That Isn't Working Very Well* (Regulatory Assistance Project, 2002); and,
>
> *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers* (Synapse Energy Economics, 2003)

11.6. Should there be a country-wide IRP (built up from the 5 Regional Electricity Distributor IRPs?)

This question could alternatively be presented as: Should there be a single Integrated Resource Plan for the Country, or should their be individual IRPs for each of the five regional electricity distributors.

The total load in Namibia is so small that it may be impractical to develop individual IRPs for each of the regional electricity distributors. A single national IRP would be much more likely to include the kind of technical analysis of loads and resources that is desirable. Alternatively, a national IRP addressing supply and transmission issues could provide a framework of analysis that more localized IRPs, reflecting local loads and distribution characteristics could build on.

In the Western United States, where IRP evolved, it has been applied only to the investor-owned utilities (the smallest of which have 1,000 – 2,000 megawatts of demand), and to the large generating public utilities such as Los Angeles Department of Water and Power, Sacramento Municipal Utility District, and the Salt River Project, which also have loads of this magnitude. While the Western Area Power Administration requires all of its customer utilities (some of which are quite small) to submit IRPs, its rules are VERY lenient with respect to the types of information required from the smaller (under 25 gWh) distribution utilities that it supplies. However, in the Eastern United States, IRP is sometimes practiced by much smaller utilities, including municipal and cooperative utilities, and has proven beneficial even in those cases

An important part of an IRP, however, is the distribution capacity constraints and distribution system expansion plans that are applicable at the local level. These will clearly be the responsibility of the regional electricity distributors. In order to compare the cost and cost-effectiveness of distributed generation alternatives to central generation plus transmission and distribution system expansion, it is essential that these elements be developed in a consistent manner. The Electricity Control Board should set forth, in its IRP rules, the manner in which local distribution system expansion and the expected loads to be served by such expansion are measured. This will permit objective consideration of distributed generation alternatives.

11.7. How much "float" on the spot market is needed for a "viable" spot market to emerge?

A viable spot market is an essential element of any competitive power supply system. The spot market provides power to meet unanticipated variations in demand, and to backfill for unexpected outages of planned resources.

The size of the spot market should be large enough that it can absorb either an outage of the largest generating facility in the system, or the type of load variations that are typically experienced on a system. However, the spot resources that are available to meet this variation should include not only generating resources being actively traded in the spot markets, but also demand response resources that can be called upon from time to time if and when price spikes occur. At the same time, the clear lesson from California is that excessive reliance on spot market purchases can lead to unacceptable volatility in power cost, which in turn can be severely detrimental to a regional economy.

It is impractical to think of Namibia in a stand-alone context in this type of analysis. During the wet season, the output of the Ruacana generating station exceeds the total consumption of Namibia, and it would be completely impractical to have a spot market that exceeds the national load. Similarly, were the Kudu gas field and associated power station to be constructed, the output of that station would exceed the national load. The size of the spot market needs to be in the context of the power pool to which it applies, in this case the entire Southern Africa Power Pool. In this context, it needs to be larger than the largest of the following "contingencies" in order to prevent the evolution of market power:

- The largest single generating facility that could fail as a unit;
- The largest single seller or buyer in the market;

- The difference in loads between "normal" peaks and "extreme" peaks.

For the power pool as a whole, even after the breakup of Eskom, this would appear to be governed by the "largest seller" contingency. This would be on the order of 15% - 20% of total load. If Eskom were to be further divided, or if new market entrants quickly grew and the Eskom spinoffs did not, the amount would fall down toward one of the other two contingency factors.

11.8. Reference Materials for Questions on Practicality of a Wholesale Market Posed by ECB Staff

Portfolio Management: Looking After the Interests of Ordinary Customers in an Electric Market That Isn't Working Very Well, Regulatory Assistance Project, 2003 (47 pages)

Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers (Synapse Energy Economics, 2003 [Draft Not Available For Release Until 10/03]

Integrated Resource Planning Criteria, Western Area Power Administration (2 pages)

Wholesale Competition Report, Minnesota Public Utilities Commission, Electric Competition Work Group, October, 1996

Wholesale Market Primer, Texas Public Utilities Commission

12. Summary and Recommendations for Future Analysis

This Report has examined many issues relating to the transition of the electricity sector in Namibia from an integrated monopoly, to a Single Buyer structure, and toward a potential Wholesale Market form of organization. It has concluded that a strong IRP process is essential in the Single Buyer context, and that there are significant barriers to achievement of efficiencies under the Wholesale Market model.

This section seeks to identify some specific issues for future research and analysis by the ECB in conjunction with its colleagues within Namibia and throughout Southern Africa.

First and foremost, the ECB needs to launch the IRP process without delay. The availability of both supply-side and demand-side alternatives, the prospect of development of the Kudu project, the wind energy potential of Namibia, and achievements possible through implementation of codes and standards for new construction and new appliances need to be evaluated on a common basis.

Second, wholesale market rules need to be developed and implemented on a consistent basis throughout SAPP. Ideally these should follow the recommendations in this report, for transparency, reporting, monitoring, and policing of market power. Absent such rules, there is no real prospect for a truly competitive wholesale market to emerge.

The ECB should consider studying further the size and number of sellers in a wholesale needed to assure viability, as this will be a key factor in determining whether the regional electricity developers should pursue independent resource acquisition. Similarly, the ECB may want to examine the staffing and training requirements for the regional electricity distributors to become viable energy portfolio managers.

The ECB should define the rules for allowing large industrial customers to directly access the wholesale market. Some means to examine whether it is desirable for these customers to leave the system is needed, and to set exit and re-entry standards for those that do. This examination needs to consider whether direct access industrial customers should participate in a system benefit charge program, how they should be required to provide reserves related to their power demand.

Last, but certainly not least, the ECB needs to establish a process for public involvement in its decision-making process, that invites all stakeholders to the table, considers all interests, and creates a standard of regulation that will be viewed as informed, fair, and objective. This Report, and the stakeholder process for which it has been prepared, are important elements of creating a regulatory system that inspires trust among all members of the energy producing, distributing, and consuming sectors of Namibia.

Annex A -- Model Rule for Integrated Resource Planning In a Single Buyer Framework

1. Purpose

The purpose of this rule is to establish a process for determining the optimal electric utility resource portfolio for Namibia, and creating a framework for the acquisition of these optimal resources. The rule sets forth an approach for measuring both supply-side resources and demand-side resources on a consistent basis.

2. Goal of Integrated Resource Planning

The goal of integrated resource planning is the identification of the resources or the mix of resources for meeting near and long term consumer energy needs in an efficiency and reliable manner at the lowest resource cost, consistent with the environmental values contained in the laws and policies of Namibia.

3. Definitions

See Attachment A

4. NamPower's Responsibilities

NamPower shall be the Lead Agency in the preparation of the Namibia Integrated Electric Resource Plan. NamPower is currently designated as the Single Buyer for retail electric load in Namibia. As such, it is responsible for resource acquisition. This rule places additional conditions on this function, to minimize cost consistent with reliability, environmental, and other considerations. NamPower is responsible for facilitating the Stakeholder Advisory Group established under this rule, for supporting the public process set forth in Section 8 of this Rule, and funding the development of the Demand Forecast and the Technical Studies called for under section 9 of this Rule.

5. The Ministry's Responsibilities

The Ministry of Mines and Energy expected to participate actively in the Stakeholder Advisory Group established by these rules.

6. Local Distribution Providers Responsibilities

Local distribution providers shall assist NamPower in the preparation of technical studies for the Namibia Integrated Electric Resource Plan. Each distribution provider shall provide NamPower current and up-to-date estimates of the distribution facilities planned for construction, and the numbers of potential customers in each geographic location not currently service by electric distribution facilities. Local distribution providers shall also cooperate with NamPower in implementing distributed energy resources as called for in the Integrated Resource Plan.

7. Customer Responsibilities

Retail Customers have the responsibility to cooperate with NamPower in the development of the Demand Forecast, and in the preparation of Technical Studies as required. During the acquisition process, retail customers have the responsibility to cooperate with the Efficiency Provider in the implementation of energy efficiency resources.

Wholesale Customers have the responsibility to cooperate with NamPower in the development of the Demand Forecast, and in the preparation of Technical Studies as required. During the acquisition process, Wholesale Customers have the responsibility to acquire resources to meet their demands that are consistent with the Integrated Resource Plan. Access to transmission and reliability services may be withheld from Wholesale Customers by Order of the ECB if these customers deviate from the Integrated Resource Plan to the detriment of achieving the Purposes and Goals of this Rule.

8. Stakeholder Advisory Group

The Integrated Resource Planning process is intended to be an open and public process, with significant involvement from the general public and from stakeholders.

The Electricity Control Board shall establish and support a Stakeholder Advisory Group (SAG), consisting of not more than twenty individuals representing diverse interests. The SAG may establish committees and subcommittees to address specific elements of the Integrated Resource Plan.

The SAG shall include, but not be limited to:

8.1 Membership

8.1.1 Electricity Consumers

- Residential consumers
- Low-income consumers
- Areas not currently served with grid electricity
- Retail businesses
- Office sector
- Manufacturing sector
- Mining sector
- Agricultural sector
- Wholesale customers

8.1.2 Electricity Producers

- Independent Power Producers
- Renewable Energy Equipment Manufacturers
- Energy Marketers

8.1.3 Electricity Distributors

- Regional Electricity Distributors
- Electricity Providers is Non-Grid Connected Regions

8.1.4 Energy Efficiency Providers

- Firms installing energy efficiency equipment
- Energy efficiency equipment manufacturers and distributors

8.1.5 Environmental Advocates

8.1.6 Academic Experts

8.1.7 Governmental Agencies

- Ministry of Mines and Energy

8.2 Role of the SAG

The SAG shall participate at each major step in the process of developing the Integrated Resource Plan. It shall consider and make recommendations to NamPower on the assumptions to be used, consultants to be retained, and contents of the Draft Integrated Resource Plan. The SAG will have automatic standing as a body in the consideration of the Draft Integrated Resource Plan before the Electricity Control Board as described in Section 9.6 of this Rule.

8.3 Financial Assistance to SAG Members

Upon application to the ECB, members of the SAG for whom participation is a financial burden may request financial assistance. NamPower will provide reasonable financial support, not to exceed the compensation of its own staff assigned to the process. It is the intent of this Rule that no meaningful contribution to the quality of the Plan should be excluded for lack of financial ability to participate on the part of a SAG member.

9. Major Steps in the Process

NamPower will complete all elements of the Integrated Resource Plan in a timely fashion, with consultation from the SAG at each step.

9.1 Demand Forecast

A demand forecast of at least twenty years duration shall be prepared. It must be specific by geographical region and customer class. End-uses shall be separately examined for at least the first five years, and may be aggregated as necessary for the remaining fifteen years.

9.2 Technical Studies

Technical studies shall be prepared by NamPower and by consultants to NamPower, with input from the SAG. At a minimum, the technical studies shall address the following topics, at a minimum:

9.2.1 Electricity Supply

9.2.2 Energy Efficiency Measures

9.2.3 Distribution Energy Measures

9.2.4 System Efficiency Improvements

9.2.5 System Integration of Demand and Supply Resources

9.3 Stakeholder Advisory Group Review

The SAG shall review the technical studies at each stage. Initially, they will review the scoping documents for each study. The SAG shall provide guidance as to whether the technical studies should be done by the staff of NamPower or by outside consultants. The SAG shall review the workplans and periodic progress reports from staff of NamPower assigned to perform technical studies. The SAG shall review the Requests for Proposals, the responses to the RFPs, and the Draft and Final reports from the consultants.

9.4 Draft Integrated Resource Plan

NamPower will prepare a Draft Integrated Resource Plan upon completion of the technical studies. The Draft Integrated Resource Plan shall set forth the Demand Forecast, identify the results of the Technical Studies, and shall identify the mix of resources which is projected to meet the Demand Forecast at the lowest possible cost, consistent with applicable reliability and environmental principles.

In developing the various sections of the Draft Integrated Resource Plan, NamPower shall consider all recommendations from the SAG, but is not bound to follow the advice of the SAG. Where NamPower deviates from recommendations of the Sag, it shall explain the reasons for the differences.

The SAG shall review each section of the Draft Integrated Resource Plan as it is developed, and shall review the completed Draft Integrated Resource Plan before it is released for Public Review. If the SAG does not agree that the Draft Integrated Resource Plan should be released for Public Review, it shall report to the ECB, which shall expeditiously consider the views of NamPower and the SAG. The ECB will then make a decision of whether the Draft Integrated Resource Plan should be released for Public Review, or remanded to NamPower for modification.

9.5 Public Review Process

The Public Review Draft Integrated Resource Plan shall be made available at public libraries and on the web site of NamPower. Members of the public shall have a minimum of 30 days to comment on the Public Review Draft Integrated Resource Plan prior to it being filed with the Electricity Control Board. NamPower may make changes to the Draft Integrated Resource Plan prior to submitting it to the ECB.

9.6 Electricity Control Board Review

Following the Public Review Draft, NamPower, in consultation with the SAG, shall file a Draft Integrated Resource Plan with the Electricity Control Board. The Electricity Control Board will open a formal docket to consider the Draft Integrated Resource Plan.

During consideration before the Electricity Control Board, the SAG shall have formal standing to comment on any aspect of the Plan. At least one hearing to receive comment from the general public will be held. NamPower will provide expert witnesses to explain and defend the elements of the Plan. The processing of this docket will follow the same rules of procedure as a tariff application.

9.7 ECB Order and Final Integrated Resource Plan

At the conclusion of the docket before the Electricity Control Board, the Board will issue an Order setting forth its findings and conclusions. The Order may accept the Integrated Resource Plan as filed, accept the plan subject to specific minor revisions, or reject the Plan.

If remanded for minor revision, the ECB shall set forth explicitly the changes that it determines are necessary for the Plan to be acceptable. NamPower shall incorporate the recommended changes, and resubmit the Plan for acceptance as a compliance filing.

If the ECB rejects the Plan, it shall set forth in detail the basis for the rejection, the sections that require modification, and a timeline for modification and resubmission. A rejected Plan must go through the Public Review and ECB Review processes in the same manner as a timely-filed Plan. If it rejects a Plan, the ECB shall set forth the conditions under which resource procurement may continue in the absence of an accepted Plan.

10. Resource Acquisition

The Plan shall set forth the methods by which resource acquisition is to be achieved.

10.1 Role of NamPower

As the Single Buyer, NamPower will acquire all generating resources, and provide the utility-sector funding for all Energy Efficiency resources. The Plan shall indicate the types of programs to be operated by NamPower in order to achieve these functions.

10.2 Role of Independent Power Producers

It is anticipated that Independent Power Producers will have a significant role in the development of new generating resources. The Plan shall set forth the type of resources and type of contracts by which relationships with Independent Power Producers will be developed. As discussed below in Section 11 of this Rule, the ECB will reserve the right to conduct prudence reviews of any contracts with Independent Power Producers, and the relationships identified in the Plan shall provide for this review.

10.3 Energy Efficiency Acquisition

The Integrated Resource Planning process anticipates a significant level of activity to achieve energy efficiency in Namibia. In order to achieve this, the Plan must set forth the manner in which efficiency investments are to be made.

10.3.1 Utility-Based

The Plan may delegate to local distribution utilities the responsibility for implementing energy efficiency programs at the local level. If it does so, the Plan shall specifically identify how the local distribution utilities are to be "made whole" for the impacts of efficiency on their systems, so that the diminished sales volume does not adversely affect the net operating income of the distribution utility.

10.3.2 Codes and Standards

The Plan may identify certain energy efficiency measures that are best achieved through the implementation of codes and standards. These shall be accompanied by specific code language and/or standards language. The agencies of government charged with implementation of the codes and standards shall be consulted during the development of the Plan.

10.3.3 Market Transformation Activities

The Plan may identify certain energy efficiency measures that are best achieved through market transformation activities, providing incentives at the wholesale or retail level to introduce new efficient products into Namibia. These shall be accompanied by program design elements of sufficient specificity to allow the Electricity Control Board to determine if the programs are likely to succeed in achieving the efficiency goals to which they are directed.

10.3.4 Energy Efficiency Utility

The Plan shall examine the option of creating a separate nationwide Energy Efficiency Utility which will receive funding from the electric utility sector, and have principal responsibility for achieving the energy efficiency elements of the Plan. The Plan shall set forth a proposal for governance, funding, and evaluation of the Energy Efficiency Utility. Any actions of the Energy Efficiency Utility shall be subject to the same review by the Electricity Control Board as would be actions of a local distribution utility.

10.3.5 Pilot Programs

The Plan may provide for pilot programs designed to "prove up" promising energy efficiency resources. Because of the nature of pilot programs for unproven resources, the Electricity Control Board will not apply the same scrutiny of prudence review to pilot programs, but must consider and accept the proposed pilot programs in the context of reviewing the Plan. Not more than ten percent of energy efficiency funding may be dedicated to such programs.

11. Prudence Review by ECB

The Electricity Control Board shall review all resource acquisitions to determine if they are consistent with the Plan, reliable, and prudently acquired. The review shall be conducted annually, through a formal docket. The Electricity Control Board may find programs prudent, may identify necessary program changes needed to achieve and/or maintain prudency, or may find programs to be imprudent. Any programs found to be imprudent will be discontinued as soon as practicable.

12. Periodic Submissions to the Electricity Control Board

NamPower will report to the Electricity Control Board periodically on the status of resource acquisition.

12.1 Major Resources

No electricity supply resource in excess of five years duration and/or more than ten percent of the peak demand or annual energy consumption of the acquiring entity may only be acquired if consistent with an accepted Plan. Such resources may not be purchased, contracted for, or obligated to unless and until it has been reviewed by the Electricity Control Board in an Integrated Resource Plan or Special Docket, and that Plan has been accepted by the Board.

12.2 Minor Resources

Electricity supply resources of less than five years duration and less than ten percent of the peak demand and annual energy consumption of the acquiring entity may be acquired without Electricity Control Board review if they are consistent with the accepted Plan. Any such resource acquisitions will be subjected to prudence review as described in Section 11 of this rule.

Experimental or promising resources not exceeding one percent of the peak demand and annual energy consumption of the acquiring entity may be acquired without Board review if the acquiring entity certifies to the Board that they believe that the resources

12.3 Periodic Reports on Implementation of the Plan

NamPower shall submit quarterly reports to the Electricity Control Board on the implementation of the Plan. Each report shall identify all generating resources and efficiency resources acquired, the total costs of each resource or type of resource, the measure life, and the life-cycle levelized cost of each resource. The reports shall also identify the resource acquisition activity underway at the time the report is filed, and the timing of such resources.

13. Cost Measurements to be Applied

All measurements of the cost of energy resources in the Plan shall be based on total life-cycle costs and benefits of measures, discounted to present value at a discount rate to be developed and explained in the Plan.

13.1 Societal Cost Test

The Societal Cost Test is the primary test that shall be applied in determining what resources are most cost-effective. This cost test includes all costs incurred to acquire a resource, regardless of what entity pays the cost, and includes quantified environmental costs.

13.2 Quantification of Environmental Costs

All environmental impacts of generating resources and efficiency resources shall be quantified, to the extent practicable, and included in the calculation of measure cost. These impacts shall be measured regardless of the physical location of where impacts occur – the cost of imported electricity, for example, shall include the marginal environmental impacts identified for the location from which the electricity is exported.

Unless the Plan demonstrates convincingly a different environmental cost, the Plan shall use default values of $N100/tonne for carbon dioxide emissions, and $N1500/tonne for Sulfur Dioxide emissions. Values for other emissions shall be developed through Technical Studies and explained in the Plan.

14. Planning Cycle

It is intended that Integrated Resource Plans be developed and reviewed on a three-year cycle.

14.1 Initial Plan

The Initial Plan will be developed on an accelerated schedule, because it is recognized that major power supply contracts will expire in the near future, and Namibia needs to take significant steps to assure and adequate, reliable, economical, and sustainable electricity supply.

The Initial Plan shall be prepared on the following schedule:

August, 2003	Notice of Intent; Distribution of Model Rule by ECB
October, 2003	Distribution of Draft Rule by ECB
December, 2003	Stakeholder Process on Draft Rule
February, 2004	Adoption of Final Integrated Resource Planning Rule
March, 2004	Stakeholder Advisory Group Formed
August, 2004	Technical Studies Completed
October, 2004	Draft Integrated Resource Plan Public Review
November, 2004	Draft Plan Submitted to ECB
December, 2004	ECB Hearing on Draft Plan
January, 2005	ECB Decision on Plan

14.2 Subsequent Plans

After completion and acceptance of the initial Plan, subsequent Integrated Resource Plans shall be prepared every third year. The key dates for the Second Integrated Resource Plan will be:

January, 2006	Stakeholder Advisory Group Formed
January, 2007	Technical Studies Completed
July, 2007	Draft Plan Public Review
October, 2007	ECB Hearing on Draft Plan
December, 2007	ECB Decision on Plan

15. Sanctions for Non-Compliance With the Plan or Process

If NamPower fails to meet the milestones set forth in this Rule, the Electricity Control Board shall impose sanctions. These sanctions may include fines, suspension of recoverability of costs for resource acquisition, suspension of recoverability of personnel costs, or assignment of responsibility for resource planning and acquisition to a different agency.

Fines of up to $N10,000 per day for each day a milestone date is missed may be applied administratively by the ECB without hearing.

Any other sanction will be applied only after notice and hearing before the ECB.

Annex B: Status of transmission pricing methods in South Africa

The development of electricity markets around the world resulted in the transmission component of electricity supply being identified essentially as a transport company. In these markets the users of the transmission networks started to pay for the differentiated services provided by the transmission company.

Eskom has favoured the development of a market-based approach to the generation and supply of electricity in South Africa. Since 1996 an experimental market has been in operation in Eskom to develop expertise and to gain experience with such an approach. Transmission tariffs were developed for this purpose. The previous approach was to charge end-users for all costs of a vertically integrated utility without reference to the cost components and their relative contributions to the total cost.

The requirements set out in the Energy White Paper, as approved by the Government, are also clearly a driving force behind this approach with the necessity to move towards more cost reflective tariffs, with sensitivity concerning existing subsidies.

The proposed result is transmission tariffs that are separate from the energy tariff. Two important principles have to be adhered to when pricing transmission services:

The first principle is to see transmission not as a wholesale purchaser of electricity that earns income by re-selling it to the next level of the distribution chain with a mark-up to cover its own costs. Transmission is seen rather as the transport company that delivers a product it never owns. In this approach transmission is forced to identify its own cost drivers to base its tariffs on; and

The second principle is that transmission is seen to be in a monopolistic position where delivery takes place using capital-intensive plant that cannot competitively be duplicated by an interested party who might want to compete with the existing transmission company in a given area of supply. The monopolistic position implies regulation to ensure efficiency in transmission and fairness of tariffs, and it implies a cost-based pricing regime that heavily influences the transmission tariff structures.

The development of a Wholesale Electricity Pricing System as an industry wide starting point to move to a market for the whole of South Africa's ESI followed where the Transmission tariffs were officially approved by the NER. Transmission has been using and developing a tariff system since 1994 as a transfer pricing mechanism between itself and the other two main Eskom line groups, namely Generation and Distribution. This development took into account the two main principles discussed above, identifying unique cost drivers to base the tariff on, and attempting to stay within NER guidelines when calculating cost reflective tariffs for the use of Transmission services.

Four different tariff components emerged from the development process:

1. Infrastructure (network) charge - Transmission customers as a group benefit from the existence of the integrated Transmission network used to deliver electricity from generators to loads. Customers pay an ***Infrastructure Charge*** for this service.

The infrastructure charge is the biggest component of the Transmission tariffs. It covers all costs associated with the running of the Network Operator, creating and maintaining a Transmission network, and (at least in principle) earns a realistic return on the investments to enable payment of finance charge, taxes and dividends. Both generators and loads are required to make a direct payment for the use of the infrastructure. As a group all generators contribute half of the revenue, with the loads as a group contributing the other half. Cost reflective locational signals are part of the design of the Infrastructure charge, dividing the country into eight transmission pricing zones, with the price profiles to generators and to loads a mirror image of each other around the average price. In total this component represents about two thirds of the revenue required by Transmission.

2. <u>Connection Charge</u> - Certain Transmission assets are set in place for the specific benefit of a single customer. This should be easy to identify and price, but sometimes it is not. Where applicable, customers pay a ***Connection Charge*** tailored to their situation. Connection charges are case specific.

3. <u>Energy losses</u> - the Transmission network consumes a small amount of energy as technical losses. The cost of the energy consumed is a cost associated with the Transmission service, and a cost based charge for ***Energy Losses*** is paid by Transmission customers. Losses charged represent about 20% of Transmission's revenue. Again the generators and the loads as groups contribute 50% each to total losses revenue. Cost reflective loss factors for the same eight pricing zones are calculated and applied to the metered energy (generated or consumed) and using the average energy rate a monthly payment is calculated. The price profiles across South Africa for both generators and loads are similar as the price profiles for the infrastructure charge.

4. <u>Reliability Charge</u> - Transmission has the responsibility to ensure reliable delivery of electrical energy and manages the System Control Centre. Various costs are associated with ensuring a reliable supply, and to enable Transmission to pay these costs all customers pay a ***Reliability Charge***. Reliability charges recover the balance of Transmission's revenue. At present it is an energy based charge to all generators and loads but development work is ongoing worldwide and in South Africa towards usage based price structures.

Using the above approach, the level of transmission tariffs on customers will vary with location. A load in Mpumalanga could experience a 2% reduction in total cost (energy cost and delivery cost) of electricity, but a load in Eastern Cape would potentially pay about 7% more. The Transmission tariff to generators is most expensive in Mpumalanga where there is more generation than load, and most beneficial to a generator in the Eastern or Northern Cape where almost no generation exists and loads are serviced using very long and expensive transmission lines.

At present the country is divided into a base price area and three surcharge areas. It is based on concentric circles with the centre point in Johannesburg, the base area having a 300 km radius, the 1% surcharge area being between 300 and 600 km from

Johannesburg, the 2% surcharge area between 600 and 900 km and the 3% surcharge area more than 900 km from Johannesburg. This arrangement is not strictly cost reflective, but could be used as an interim approach to prevent price shocks to consumers. In this scenario both the infrastructure charges and the losses charges would be calculated to reflect base prices and 1%, 2% and 3% surcharges.

Annex C: Congestion Management in the proposed RSA Multi-Market Model

It is generally not efficient to provide a completely constraint free transmission system (as this would generally require considerable over-investment), and some restrictions will therefore occur in operation from time to time that need to be managed. There may be some persistent bottlenecks between discrete areas of a system or across international borders as well as transient limitations due to a combination of loading conditions and perhaps a depleted network due to maintenance outages. Described below are three generic alternatives for dealing with transmission constraints.

Option 1: Market splitting

One option is to operate a constrained DA. This means that those constraints that are identified beforehand can be incorporated into the market. This typically takes the form of defining two or more price zones, where zones are separated by the constraint. DA prices in each zone will be set to balance supply and demand in each zone, taking in account the transmission capacity and trade between the zones.

Participants exposed to prices in a particular zone can enter into hedging contracts to manage their exposure to the resulting price differentials. Financial transmission rights (FTRs) are one such mechanism that allows participants to hedge this form of price risk.

Option 2: Transmission access rights

Another option is to require participants to hold firm transmission access rights, and only be allowed to inject or extract power if they hold sufficient rights. These rights can be allocated or auctioned, and can be traded through a secondary market. If insufficient transmission capacity arises, the System Operator will have to repurchase these rights to resolve the constraint, and a market mechanism can be created to allow this to happen. This may give rise to reasonably significant market power problems of its own.

Option 3: Counter-trading

A third alternative is to allow the System Operator to resolve the constraint through "counter-trading". This implies that the System Operator constrains generators on or off to resolve the constraint, and pays them to do so. The resulting costs are part of the System Operator's costs and are recovered through charges to participants ("uplift").

Combining options

It is possible, and usually necessary, to utilise a combination of measures to resolve constraints. For example, market splitting can only be used where the constraint is predicted at least a day ahead of time, and is typically used for persistent and known constraints. This would usually be combined with counter trading to allow the System Operator to resolve transient constraints.

Preferred solution

Our preferred solution, at least for the initial market design, is the use of counter trading. However, we believe that, as experience with the market grows, participants should consider the use of market splitting or transmission access rights.

Our preference is justified by:

The greater simplicity of this solution, at least with respect to the operation of the DA and the price risks that participants are exposed to.

In the South African context, there are limited options to resolve the persistent constraints on the transmission system, implying market power for certain generators. Mitigation measures need to be put in place to handle this, which are most easily implemented through contracts held by the System Operator. These contracts are well placed to be used in a counter-trading scheme.

The cost of resolving constraints through counter-trading is expected to be small as a percentage of market prices. Hence, the scale of the problem does not justify more complex solutions.

However, we recognise that there is a risk that generators may be able to take advantage of the counter-trading system by creating constraints through bidding behaviour in the DA, hence forcing the System Operator to pay to resolve the constraint. While this problem may also arise in other solutions, counter-trading would tend to be particularly vulnerable. Consequently, we believe that alternative solutions should not be excluded from the market design, and possibly introduced as experience is gained.

Further, we suggest that the System Operator be incentivised to minimise the costs of constraint resolution. This implies the regulator including constraint resolution as a portion of an income cap for the Network Operator of the Transmission Company. This also provides better incentives for the Transmission Company to judge the merits of a particular transmission strengthening investment in relation to the constraint costs thus avoided. This is not an element of the market rules, but rather a regulatory issue and outside the scope of this project.

We also recognise the market power that specific generators may have as a result of persistent constraints (or their physical location), and recommend that, in the case of disputes, the regulator has the authority to intervene in the contracts that the System Operator wishes to enter into, using a published price determination methodology.

Finally, where a constraint is not persistent, but may endure for an extended period (for example as a result of an extended transmission line outage), specific generators may have market power for that period. In these cases, significant deviation from historical bidding behaviour should trigger an investigation by the market surveillance body (a function of the NER), with the authority to recommend or impose controls on that generator.

Annex D: Wheeling Loss Compensation Operational Implementation

1. Data Input Requirements

a. Utilities whose networks participate in wheeling shall provide the Co-ordination Centre by 31st October with the following information by completing a standard form: -

* Annual Maximum System Demand for current year

* Typical daily load profile data

* Network updates undertaken and commissioned, or to be commissioned before January of following year

2. Incremental Loss Determination

a. The Co-ordination Centre shall ensure that the SAPP PSS/E load flow model is updated to reflect all network changes as advised by the utilities. This process of model updating is continuos and done as and when additions to the network are commissioned.

b. The Co-ordination Centre shall derive two maximum demands (MD) for winter and summer seasons as follows: -

* Winter Season (May to September) – Utility provided MD's are used without any scaling.

* Summer Season (October to April) – Utility provided MD's are scaled down to 80%.

c. The Co-ordination Centre shall perform load flow simulations to determine the incremental losses for all probable wheeling paths.

* The wheeling transactions shall be simulated in multiples of 5MW. This is in line with the lowest trading level stipulated in STEM Book of Rules.

* For every wheeling path the simulations must be done for both directions.

* The typical load profiles provided by Utilities are used to derive hourly system demands for 24 hours of the day. Simulations are then done for each hourly system demand.

d. The Co-ordination Centre shall produce a set of four incremental loss tables for every wheeling path and provide the same to SAPP members by 31st December . Each incremental loss table will cover a suitable range of wheeling transactions.

* A table for each direction of flow for the winter season

* A table for each direction of flow for the summer season

  e. The SAPP members will perform a sanity check to confirm the incremental losses determined by the Co-ordination Centre are reasonably acceptable.

  f. The Co-ordination Centre will present the incremental loss tables to the OSC at its February meeting for approval and implementation on 1st March.

3. Incremental Loss Accounting

  a. The loss accounting is done in arrears at the end of the month.

  b. Utilities involved in wheeling shall agree and submit the dispatch schedules for the previous month to the Co-ordination Centre by the 5th working day of the current month.

  c. The Co-ordination Centre computes the hourly losses to be compensated to the wheeling utility which are summated into peak and off peak totals:-

* Peak losses – The peak definitions in the SAPP agreements apply.

* Off – Peak losses – The off peak definitions in the SAPP agreements apply.

  d. The Co-ordination Centre shall provide the utilities with the peak and off-peak losses for the previous month and the cumulative losses to date.

  e. The wheeling utilities and buying utilities shall agree on when and in what quantities the losses will be paid back.

  f. The wheeling utilities and the buying utilities shall advise the Co-ordination Centre of any payback schedules and implementations.

4. Treatment Of Multiple Transactions

Multiple transactions in the same or opposite directions normally result in higher or lower incremental losses compared to the total losses derived from individual transactions.

  a. For multiple transactions in the same direction, the losses due to the ***summed transactions*** are apportioned to the individual parties in proportion to their individual transactions.

  b. For transactions in opposite directions, the losses due to the *netted transactions* are apportioned to the individual parties in proportion to their individual transactions.

c. In both cases, Utilities whose individual transactions would result in negative losses in the wheeler network shall not be apportioned losses.

5. Examples

Day	Hour Ending	ESKOM Import SNEL	SEB Import ZESCO	Total Dirtn 1	ZESCO Import ESKOM	Total Dirtn 2	Total NET	Applied Losses
2 April	01:00	0	50	50	0	0	50	0.3
2 April	02:00	0	50	50	0	0	50	0.3
2 April	03:00	0	50	50	0	0	50	0.3
2 April	04:00	0	50	50	0	0	50	0.3
2 April	05:00	0	50	50	0	0	50	0.3
2 April	06:00	110	50	160	-70	-70	90	1.2
2 April	07:00	110	0	110	-100	-100	10	0
2 April	08:00	110	0	110	-100	-100	10	0
2 April	09:00	110	0	110	-150	-150	-40	0.2
2 April	10:00	110	0	110	-150	-150	-40	0.2
2 April	11:00	110	0	110	-70	-70	40	0.4
2 April	12:00	110	0	110	-50	-50	60	0.4
2 April	13:00	110	40	150	0	0	150	3.0
2 April	14:00	110	40	150	-50	-50	100	1.4
2 April	15:00	110	30	140	-80	-80	60	0.3
2 April	16:00	110	0	110	-80	-80	30	0.2
2 April	17:00	110	0	110	-100	-100	10	0
2 April	18:00	110	0	110	-100	-100	10	0
2 April	19:00	110	0	110	-150	-150	-40	0.3
2 April	20:00	110	0	110	-150	-150	-40	0.3
2 April	21:00	110	70	180	-100	-100	80	1.4
2 April	22:00	110	50	160	-80	-80	80	1.3
2 April	23:00	0	50	50	0	0	50	0.3
2 April	00:00	0	50	50	0	0	50	0.3
	TOTAL - PEAK							6.52
	TOTAL – OFF PEAK							6.0

a. **Consider hour ending 13:00**

The losses due to wheeling 150MW are 3.0MW. These will be apportioned to ESKOM and SEB in the ratio of their individual transactions (110 & 40) to give 2.2MW to ESKOM and 0.8MW to SEB. The losses due to individual transactions, that is 1.4MW for ESKOM's 110MW transaction and 0.4MW for SEB's 40MW, only add up to 1.8MW and will not be considered.

b. *Consider hour ending 14:00*

Due to multiple transactions in opposite directions the net wheeling is 100MW. The corresponding losses of 1.4MW will be apportioned to ESKOM, SEB and ZESCO in proportion to their individual transactions as follows: -

Utility	Transaction	Losses
ESKOM	110	0.77
SEB	40	0.28
ZESCO	50	0.35